COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:)
)
Examining Critical)
Issues in the Licensing) Docket 00-SIT-2
of Thermal Powerplants)
and Related Facilities)
)
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CALIFORNIA ENERGY COMMISSION

1516 NINTH STREET

HEARING ROOM A

SACRAMENTO, CALIFORNIA

THURSDAY, JANUARY 25, 2001

10:00 A. M.

Reported by:
Valorie Phillips
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COMMITTEE MEMBERS PRESENT

Robert A. Laurie
Presiding Member

Robert Pernell
Committee Member

STAFF PRESENT

Scott Tomashefsky
Adviser to Commissioner Laurie

Ellen Townsend-Smith,
Adviser to Commissioner Pernell

Richard K. Buell
Siting Project Manager

Bill Wood
Natural Gas Forecaster

P R O C E E D I N G S

PRESIDING MEMBER LAURIE: My name is Robert Laurie, Commissioner at the California Energy Commission and Presiding Member of the Commission's Licensing Committee

On the dais, to my right, is my colleague on the Licensing Committee, Commissioner Robert Pernell.

COMMITTEE MEMBER PERNELL: Good morning.

PRESIDING MEMBER LAURIE: To the Commissioner's right is his adviser Ms. Ellen Townsend-Smith and to my left is my adviser, Mr. Scott Tomashefsky.

We deeply appreciate your attendance today and let me take a moment to discuss very briefly the Committee's purpose for asking you to join us today.

One of the Commission's primary mandated responsibilities is to process Applications for the Certification of powerplants. And from our experience we learned that there are a number of issues that are common to most such applications, today, but some of those issues differ from year to year or even from decade to decade.

So the Commission is examining what

issues might affect our ability to license powerplants in the future. And some of those issues could, not necessarily would, but could include such subjects as constraints on gas supplies, transmission constraints, constraints on water supplies, land use issues, local opposition and such.

And it is our purpose to seek information so that we, and thus you, have a good and proper understanding of those kinds of issues that we should be aware of in the future and not necessarily assume that no problems exist and there will be an automatic processing of licensing applications, which clearly will not be the case, but knowledge of what barriers exist to our ability to license plants is something that we all need to be cognizant of today.

So the issue of natural gas supply is first on our agenda. We deeply appreciate your attendance. We will have to move forward in a timely fashion today, because there is an awful lot to cover and, again, we appreciate your participation.

Commissioner Pernell, did you have any opening comments, sir?

COMMITTEE MEMBER PERNELL: Thank you, Commissioner Laurie.

I would just add that this is an information sharing gathering and we're here to listen and learn and gather as much information as we can. So with that, I want to thank Commissioner Laurie for setting this hearing up and we'll just move forward together.

PRESIDING MEMBER LAURIE: Thank you, Commissioner Pernell. I think agendas are out front. Our intent is to have a brief presentation of staff's overview, which has been presented in a well-drafted paper, thank you, Mr. Wood and gentlemen. We'll then ask our volunteer panel to offer comments and, again, we're going to have to look at our time. I don't know the extent to which that has been discussed.

Scott, has there been any coordination regarding timing of presentations at all?

MR. TOMASHEFSKY: We're looking at about 15 minutes per.

PRESIDING MEMBER LAURIE: Which I understand allows you about one-tenth of what you know and we appreciate that.

(Laughter.)

PRESIDING MEMBER LAURIE: We'll see what we can do.

Scott, any comments from you at this time? Otherwise, I'm prepared to go to Mr. Wood.

MR. TOMASHEFSKY: No, just that we are webcasting, that's the only other thing we need to know.

PRESIDING MEMBER LAURIE: Thank you. We are on the Internet and this workshop is being recorded. The reporter will let us know if there's any challenge to that and we'll stop the proceedings until the matter is repaired.

So at this time I'd like to call on Bill Wood for a summary of staff's presentation.

Bill.

MR. WOOD: Thank you, Commissioner Laurie.

Before we get started, it's been pointed out to me that there's a couple little minor things that need to be corrected in the staff workshop paper. In several locations I have misnamed the PG&E Gas Transmission Northwest Pipeline Company. On the first page I call it Pacific Gas and Electric's -- Gas Transmission. Again, that should be -- what should be substituted there should be PG&E Gas Transmission -- Northwest.

And then again on page 3 in two locations it's indicated as being -- this is two paragraphs above Table 1. It says PG&E Transmission Northwest and it should be PG&E Gas Transmission -- Northwest. And also in the notes on Table 1, the first note should have been inserted, that should read PG&E Gas Transmission -- Northwest.

And then when I was preparing Table Number 2 I made a mistake by not taking out a decimal point and a number, rounding things off to the nearest millions of cubic feet. So under PG&E for the year 2004, the 9,518 should be actually 952. So round that off to 952. That's the limit of the corrections that have been identified to this date, Commissioner.

One of the findings that this Commission must make in siting new powerplants is that there will be an adequate supply of fuel available for the powerplants. This, for the most part in California and for the plants that we've been reviewing is natural gas.

Staff believes that there are more than

adequate natural gas supplies available to meet the needs in California. I'm thinking in terms of potential resources, both in the U. S. and Canada. There is enough potential resource in the U. S. to serve up to 50 years of supply or demand at current demand levels by using current exploration drilling and well development technologies.

Our concern, rather, is not so much with the supply then, but is there sufficient reliable transportation to bring the gas from the wellhead to California and then, once it's to California, to where it will be consumed inside the state.

To illustrate our concerns in this regard let me illustrate what's been happening during this last week. Last week, California consumed in the area of nine thousand three hundred million cubic feet per day. That's an astronomical quantity of gas.

That's normally associated with an adverse peak day occurring simultaneously in northern and southern California. It compares to an average last year of sixty-one hundred million cubic feet per day for the year and previous years of around fifty-five hundred million cubic feet per day.

Utilities have been sending out in the area of eighty-six hundred million cubic feet last week, and the non-utilities, our gas supply that was going directly to end users, either from Kern River and Mojave pipelines are directly from California production, was in the area of 750 million cubic feet per day.

To meet the level of demand that we had last week, our pipes were running nearly full. The pipes coming, the interstate pipes coming to California were nearly full and our utilities' receiving capacity was at or near their ability to receive gas from all supplies.

In order to assure that this level of demand was met, 2600 million cubic feet a day was pulled from storage. During this period of time, powerplant requirements were in the area of 3000 cubic feet per day. Normal for this time of year is in the area of about 1200 million cubic feet per day.

So what we're seeing in powerplant demand during this winter is something that's more comparable to what we would normally see on an average day in August, if you would.

Now, looking into the future, our

forecasted demand indicates for this year that we're going to have a demand in the area of about 6400 million cubic feet per day, and I believe that we're going to be very close to that.

For the next five years or so our forecast is flat. That in or about 6400 million cubic feet per day, even though we have a number of new generation facilities coming on line. And then after, beginning in 2005, a demand starts escalating which will reach, we believe, in the area of 7600 million cubic feet per day.

Now these demand levels compare to a capacity to receive gas in California of 7,000, so currently at an average annual level of 6400 million cubic feet and a capacity of 7,000, that's a 91 percent load factor. It doesn't leave a lot of room for getting gas in the storage that we need on those peak days, for use in peak days in the winter and in the summer.

Our overall gas demand for the next ten years indicates and is in the area of about 1.7 percent per year.

And California is not the only area where gas demand is increasing. I also indicate in the paper that new powerplants are going in in all the states surrounding California and a number of these are being sited directly on pipelines which will further require capacity on those particular pipes.

So we're in a situation then of we're looking at what's going to happen on a peak day, peak adverse day in the wintertime or what's going to happen on a peak demand in the summertime.

We've already seen some occurrences of curtailment that has occurred in San Diego, principally because they just don't have the flexibility to meet a high demand. But we are also seeing that, for instance, in the SoCal service area that they've been running at or near capacity since June, and in PG&E service areas it's a similar situation. And both utilities, their storage levels have drawn down considerably from where they would like to be at this time of year.

So the questions that we have in this area, then, given this level of demand that is now occurring, is this something that we're really going to be seeing in the future?

Our speculation is that powerplant demand is going to continue at levels that are near what we are looking at now. We're looking at something in the area of 2300 million cubic feet per day, staying at that level, and then growing to about 3300, if I remember from the table in ten years from now.

So the question arises then, is our interstate capacity to receive gas into California adequate or do we need more capacity and if so, what are our interstate pipelines doing to bring that capacity to California.

With regards to the gas utilities, do they feel that their in-state capacity is adequate to meet the growing demand that we see that is going to occur in California. If not, what kinds of things do they think they need to do to their systems to beef up, if you would, their receiving capacity as well as what do they need to do with regard to storage to add more flexibility into their systems.

And then, of course, we have 15 to 16 percent of our current supply is coming from California production. Is there anything that can be done to spur that so that we could get a higher level of production from California, say, increase market share to 20 percent rather than at 15 percent.

Now, the California delivery system has developed over the years and has been deemed to be adequate, but this system was developed with the idea that it would never supply a hundred percent of the demand a hundred percent of the time.

The idea was that there would always be, that when you hit a peak adverse day, that you could curtail your noncore customers. And in the old days these noncore customers had alternative fuel capacity and particularly we were looking at powerplants. They were the first to get curtailed and they represented a very large demand. And these plants no longer have alternative fuel capability.

This is due to economics that have occurred during the last few years and where we have experienced very low gas prices. We had a lot of new pipeline capacity added for delivery gas to California, which provided more flexibility and then, of course, there's been the air quality situation which has developed that indicates that natural gas is the fuel to be used and other fuels are something that should not be used.

So we no longer then have alternative

fuel capability for our noncore customers, even though the utilities' delivery systems were designed to incorporate those.

Within the state there are only five locations left where powerplants can still burn natural gas. These are the Encino and South Bay units in San Diego, the Potrero unit in San Francisco and the two PG&E units at Humboldt in Eureka.

Powerplants are included as one of those customers that will be curtailed in the period when natural gas demand exceeds gas supply. When that occurs, then these units will have no alternative other than to back off on their generation and in so doing then reduce the amount of energy that is available to meet California's electricity requirements.

Hopefully, if this were to occur that there would be other sources of energy to replace that, but as things have been looking this last year, that hasn't been the case.

So think about what would happen if this were to occur now that we had to curtail. Incidentally, for your information, there's been from seven to 12,000 megawatts of gas-fired generation that has not been available due to maintenance -- unscheduled or scheduled maintenance that has been going on in California. Given the supply levels that we have had in California it's doubtful in my mind that has been sufficient or adequate capacity to bring additional gas into the state to meet those powerplants if they had been operational.

It would have required, actually, for the utilities to actually pull more gas out of storage to meet that requirement and I'm not certain that they could do that because that gas is actually dedicated, or a good portion of that gas is dedicated in meeting the core market and not the noncore or electric generation requirement.

So that gets us down then to another series of questions that we have posed here. Are the present curtailment rules adequate as being, or should they be revised, and in so doing, if they should be revised, should they take into account the higher firm demand that should be associated with meeting powerplant requirements. And in so doing then, if powerplants are to be included in the meeting of this requirement, then is new capacity going to be needed within the utility systems to meet that requirement.

And when you develop new curtailment rules oftentimes that's going to cross over a lot of different entities and agencies that I've indicated in the report.

But another area that we might want to consider is is there the potential for alternative fuels to be used at powerplants? Sometimes these alternative fuels will sit for several years before they need to be used, but is there a need to have alternative fuels for reliability's sake and to ensure that we will have the electricity we need to meet our requirements without having to go through rolling blackouts as we've had for the last couple of weeks in northern California?

And then there are a number of alternatives that come to mind with regard to what those fuels could be. Of course, heavy residual fuel is one that's been used in the past, jet fuel or diesel fuel for the peaking units and there's also a new, what they call a clean diesel that's being developed based upon gas to liquids conversion from remote gas.

For instance, remote gas that's located

in Alaska or other locations could also be a potential alternative fuel that could be used.

And then, of course, how can we balance our environmental requirements and also still have the energy that we need for meeting California's needs.

That concludes my presentation, Commissioner.

PRESIDING MEMBER LAURIE: Thank you, Bill, very much.

At this time I would ask you to introduce the Panel Members, if you could?

MR. WOOD: Sure.

PRESIDING MEMBER LAURIE: And again, gentlemen, I would ask you to -- first of all, Rick, maybe we need to turn the volume. It's really important that everybody in the room be able to hear and that's always a challenge. And then you have to get very close to these microphones to the point where, by the time you're done, I will be able to announce you're engaged.

(Laughter.)

PRESIDING MEMBER LAURIE: So, just be aware of that we really need to hear. That's about as far as it could go.

Okay, Bill, thank you.

MR. WOOD: Okay. To my right is Steve Watson. He is from Southern California Gas Company. To my left is Dan Thomas, he's from PG&E. And to his right is Eric Eisenman, representing Pacific Gas -- no, who are you representing?

MR. EISENMAN: PG&E Gas Transmission Northwest and PG&E National Energy Group.

MR. WOOD: Okay. And I got these two guys switched, but one of them is Craig Chancellor and the other one is Kirk Morgan. Kirk is from Kern River Transmission and Craig is from Calpine.

PRESIDING MEMBER LAURIE: Thank you, Bill, very much.

Do we want to have Mr. Morgan go first?

Mr. Morgan.

MR. MORGAN: Okay, that's fine. I'm not quite sure how you control the slide machine there.

I am Kirk Morgan with Kern River Gas Transmission Company, in case that wasn't clear. We certainly appreciate the opportunity to be here this morning and the opportunity to share some information with you regarding how Kern River intends to respond to what we foresee as a demand for new gas supplies into California.

I just need the next slide and I'm not sure who I'm looking at for that. Okay.

The first slide is just a who we are slide. Williams Gas Pipeline has five pipelines nationwide. I think we deliver somewhere in the vicinity of 17 percent of the gas throughout the nation.

In Salt Lake City where I'm located, we manage the northwest pipeline and the Kern River System and I think there's opportunities for both of those pipelines to expand and increase capacity and deliveries into California.

Next slide.

COMMITTEE MEMBER PERNELL: Excuse me, what percentage do you deliver to California? Do you have that?

MR. MORGAN: To California it's a small percentage, probably ten percent, I think, it's what's in the staff report. We have a delivery capacity to California of 700 million cubic feet a day on a firm basis.

We are planning on the Kern River System back-to-back expansions. One in 2002 to be in service in May and one in 2003, also to be in service in May.

And what we see driving those expansions is really a convergence of market forces. First of all and probably most importantly, new generation being cited in California and Nevada. There's also been a dramatic increase in production in the Rocky Mountains.

In addition, new infrastructure developments, mainly alliance and northern border have caused an increase of competition for western Canadian gas resources and an increase in that commodity supply price in Canada.

For the last two years we've embarked on a rate reduction program on Kern River and we are able to offer now substantially reduced rates for transportation on Kern River.

And lastly, what we're seeing is a lot of demand being developed upstream of California and not just on Kern River, but on all the pipes. If you look at electric generation proposals in Arizona, in Nevada or in Washington and Oregon, a lot more gas is being consumed upstream on the interstate pipes than has occurred in the past.

The next slide is just showing the

individual powerplants that are proposed on Kern River and there are a substantial number of them. As you can see there there's probably 10,000 megawatts that potentially could be directly served from Kern River, and an additional 4,000 or so that may be served through interconnections with Socal Gas and PG&E.

That 14,000 plus megawatts represents well in excess of two Bcf of additional gas supply a day. Now we certainly don't believe all of that will ultimately be constructed, but given any percentage of it, it's still a lot of gas that needs to be developed.

You may notice that many of the generators have projects in both California and Nevada and I think that's true of Oregon and Washington and Arizona as well, so it does raise an issue as to where those powerplants will be built. Will they be upstream of California and leave California as a net importer of electricity or will those plants be developed in California and help you remain energy self-sufficient.

MR. TOMASHEFSKY: Kirk, another quick question. What impact has El Dorado had on supply to California since it's come into operation?

MR. MORGAN: El Dorado is served, in part, off of Kern River and, in part, off of El Paso through a Southwest Gas interconnection. So we are delivering a large volume of gas to the El Dorado plant. It just depends on how they decided to source it on any given month, however.

The next slide just shows the location of those plants and obviously you can see a cluster of them in Nevada and a cluster of plants along Kern River's main line. Actually that's along what's known as the common facility. It's owned by Kern River and Mojave pipeline in California.

And what's significant there is there's only one of them that's in operation right now and that is El Dorado. One of them, La Paloma is under construction and the rest are in various stages of either having been permitted or are still waiting to receive their permits.

But given the tightness of the gas supply market today you can just imagine what would happen if a large number or a large percentage of those plants are built.

We clearly think that it is a signal that we need to expand our main line from the

Rocky Mountains to California.

Next slide, please.

Wyoming is experiencing a production boom of sorts. This information is from GRI, but we feel like it is fairly accurate. Between now and 2005 we see close to a BCF of incremental production coming on in Wyoming alone. And that's coming largely out of the Powder River Basin, the Madden Field in the Wind River Range, the Jonah Field in the Green River Basin and in the future from the Pinedale fields and a lot of that production is wanting to come west.

California markets, Nevada markets are considered premium markets and we're seeing a lot of interest in our expansion projects from those producers. On top of the Wyoming supply, there's also additional supplies proposed to be attached to Kern River out of the Uinta Basin in Utah and the Ferron Fairway also in central Utah.

Next slide.

I mentioned the impact of Alliance in Northern Border and I think that is significant. You know Alliance was 1.3 Bcf going to the Chicago market out of Western Canada, both BC and Alberta, and it has tightened gas supplies. We operate the northwest pipeline system that interconnects at Sumas Washington. Prices at that border have done the same thing as the Cal border, they're very high.

Supply basin prices are much higher coming out of Canada and that, combined with transportation rates that are higher than Kern's to get all the way to Southern California, anyway, again support expansion of the Kern River pipeline out of lower priced Rocky Mountain gas supply basins.

I guess what we see the impact of that being is that there'll be less gas supply coming from western Canada, from BC and Alberta. We see that the Rocky Mountain and San Juan Basin will return back to their traditional western markets in what is sometimes termed clockwise rotation. That is pretty well accepted, I think among industry observers.

From a production standpoint, San Juan Basin has been projected to be declining for a lot of years, but it never seems to and we still see that basin being flat. But increases in production in the Rocky Mountains will continue as the previous slide shows.

Again, the conclusion there is that we need more economic takeaway from the Rocky Mountain supply basin to serve both California, Nevada and markets in the Pacific Northwest. And, in fact, we see an opportunity to bring Rocky Mountain gas along the northwest pipeline interconnecting with PG&E Gas Transmission Northwest and creating an Opal to Malin path an economically viable project.

Next slide.

The next slide deals with our rate strategies and going back to '99 we have been -- first of all, let me say, for most of its operating life, nine years now, shippers on Kern River have been under water. The basin differentials between the Rocky Mountains and the Cal border have not supported the rate that they're paying for Kern River.

And we embarked a couple of years ago on a program to lower our rates, to bring them into the market and by doing that make it attractive to expand the pipeline.

The first thing we did was lower our rates in our rate settlement in 1999 by two cents per thousand cubic feet of natural gas. That rate reduction was coupled with a rate design shift. We moved away from a straight fixed variable design and moved a portion of our fixed cost into the commodity portion, the variable portion of our rate. That was six cents and what that means is if you don't flow you don't pay it. Otherwise, under a straight fixed variable rate design you're paying a large reservation charge.

We also implemented a revenue sharing provision where revenues over a certain revenue threshold are shared 50-50 with all of our firm shippers. And, just as an aside, that amount this year will result in about a slightly over a three-cent rebate on our demand charges to all our firm shippers.

We also implemented an extended term rate program where we gave our shippers the option to extend their contracts for either a five or ten-year term and in doing so we stretched the depreciation of the pipeline, we refinanced our debt and we relevelized the rate over a longer term. And that was the most significant rate reduction idea that we had. It lowered our rates from about 64 cents a decatherm to 42 cents and that rate is very economic to come all the way from the Rockies into California.

Our next rate reduction strategy is not really a rate reduction, but a value added strategy. On September 1st, we're proposing to open up segmentation on the pipeline. We haven't segmentation on Kern River since its inception and actually you may not be familiar with that term. There's not a lot of segmentation that occurs to California. But what that enables a shipper to do is to use its single transportation path for multiple transportation transactions and by doing so it adds substantial value to those shippers.

They're able to use those individual transportation transactions to help pay for the reservation charges that the pipeline collects. Just a quick example of that would be a Kern River shipper would be able to move gas from Wyoming to Salt Lake City and serve a delivery there, and using that same capacity pick up more gas in Central Utah, a new interconnect point called Elberta, move that gas to Nevada and serve a market there.

Using their same capacity they could then pick up gas, perhaps, at Oxy Elk Hills and move it in a backhaul direction. We would like to see future interconnections, perhaps with PG&E and SoCal that would enable those systems to deliver into Kern River to create more robust segmentation opportunities and create a more integrated gas transmission grid.

Next is our first expansion. We held an open season for that last July. We have subscribed and contracted on a firm basis 124.5 million cubic feet a day. That will lower the rates again from 42 cents to about 40 cents on our 15-year contracts.

However because those expansions on Kern River use compression only there is an additional fuel use component which adds back slightly. So the net reduction, including fuel, will be about one cent as a result of that expansion, making our effective rates about 41 cents.

Next slide, please.

PRESIDING MEMBER LAURIE: Kirk, I'm going to have to ask you to start summarizing your slides a little bit.

MR. MORGAN: Okay. That means I'm out of time.

PRESIDING MEMBER LAURIE: And let me again, apologize in advance to everybody. All of you folks have a great deal of knowledge and we wish we could spend days doing this. Unfortunately we can't, so --

MR. MORGAN: Yeah, I understand. Let me just touch briefly on two issues, then.

Our second expansion is currently in an open season. It closes January 31 and will determine the volume of a second Kern River expansion, and so I wish I had the results of that today, but we've seen a lot of interest in it and we should know more next week.

I did, in the presentation, talk about three issues on the regulatory side. One of them is a tariff provision in SoCal's tariff called the residual load service tariff. It's something that both the pipelines and the electric gens have been opposing for sometime and you can refer to all that testimony to see why.

Secondly, we do see capacity limitations on the intrastate pipelines. I think it won't solve the problem to expand upstream. We need to see expanded access to SoCal, in particular, probably at Wheeler Ridge or other receipt points. And we finally like other industrial users have emissions problems. We would like to see a variance or exemption to allow gas transporters to actually use gas to compress and expand their systems rather than being forced to buy electricity.

That's the summary.

PRESIDING MEMBER LAURIE: Thank you, Mr. Morgan, very much. Excellent presentation, we appreciate it.

Bill, who would you like to have go next?

MR. WOOD: Why don't we just go right down the order that we have here. So we'll just stay with pipes and then we'll go to utilities and then Craig, representing a user.

MR. EISENMAN: Good morning. Today I'm representing the PG&E National Energy Group and its various business activities, including PG&E Gas Transmission Northwest, the North Baja Pipeline and for a bullet or two I'll have a generator hat on as well. Though the last time I appeared before you I had, I believe, four lawyers with me at Otay Mesa hearings. Today I'm pleased to tell you I have no lawyers with me.

(Laughter.)

PRESIDING MEMBER LAURIE: You don't know

how much that pleases us.

(Laughter.)

MR. EISENMAN: I have way too much material for 15 minutes, so I will probably skip over a number of the slides. I have a few more copies of my presentation up here.

Go ahead to the next slide.

This slide is a quick overview of our transportation system in the northwest, running from the Canadian border to the California border. The capacity to California is about 1900 MMcf a day.

Through my presentation I'm trying to respond to the questions that were in the notice. Going to the next slide, the first question dealt with the cost of building new pipeline capacity. And I think the long and short of that is it just depends. And there's a number of variables that need to be considered and I've tried to get a real short list of those.

Going to the next slide, there was an article a year and a half ago in Oil and Gas Journal about the dollars per mile of building gas pipelines and you can see it just is a tremendous range. That high number is a small pipe -- short pipeline in an urban area. But if you want to use kind of a round back of the envelope number, probably something a little over a million dollars.

For our pipeline system in the northwest, the first expansion proposal that we have out there for service next year, you can see it's about $115 million for really not that much pipe and some compression.

The North Baja Project, which is a Greenfield brand new project, it's 215 miles of pipe and it will cost about $240 million.

PRESIDING MEMBER LAURIE: How significant in the cost per mile is additional right of way. That is when you look at new pipeline capacity out of all that new capacity that's required, how much can go into current rights of way as opposed to what new rights of way are required, because I know how difficult that is.

MR. EISENMAN: Well, for the system in the northwest, most of the route we have adequate right of way for looping, but there will be a few places where we would have to acquire new right of way. The system coming from Canada is two parallel right now that have been built over the last 40 some years.

This expansion and further expansions will start a third loop. Most of the area we're okay on that. Certainly the north Baja pipe, since it's a brand new pipeline, we need to go acquire right of way.

COMMITTEE MEMBER PERNELL: Is there a projected completion date for North Baja?

MR. EISENMAN: Yes, it's September, 2002.

Going to the next slide, you ask, the notice asked the question about the steps needed to add new pipeline capacity. This is a quick list of it, pretty much in order, but some of these may get switched around a little bit.

The first variable is just getting the market commitment and having some sense as to how much it would be and then going through the FERC process, other permits, buying the pipe and the compressors, getting the money, building it and putting the pipe into service.

PRESIDING MEMBER LAURIE: How long does it take for FERC approvals on average?

MR. EISENMAN: Well, I hate to keep

saying it just depends, but you've typically got to expect a year, maybe a little longer. The environmental review tends to be what takes the longest.

The nonenvironmental issues, especially if noncontroversial can go pretty quickly.

The next slide, who is making the decision to seek new pipeline capacity and who has the responsibility for providing that approval. Well, it's really the market and customers who are going to drive pipeline expansions. Kirk talked about all the generators on his system, that's what is driving a lot of the expansions out here in the west on all the pipelines.

And the reality is we don't see merchant pipelines yet, like we see merchant generators, so you need that kind of market commitment to get approval from FERC and also to get financing. And while FERC might have that final approval, sometimes the local permits may actually take longer to get, so you kind of have to do everything in a parallel path.

Next slide, please.

What are the federal and state regulatory processes for approving pipeline projects? This very quickly sums up the FERC approval process from application to final certification. You will note a preliminary determination, which I think gets to the question I just responded to is FERC will often issue a preliminary determination on nonenvironmental issues so that there is some market certainty, both for the customers and for the pipeline, but before the environmental reviews are completed.

Going to the next slide intrastate pipelines here in California need to go to the CPUC and I think I've pretty much addressed the rest of this, that there is some state approvals needed for interstate pipelines as well.

PRESIDING MEMBER LAURIE: What does the PUC use for environmental documentation, do you know?

MR. EISENMAN: I think it depends on the particular project, but there often has to be, if it's a real big project, there has to be an EIS or an EIR of some kind and we will see either the CPUC or State Lands involved. Right now, with the North Baja project, FERC is the lead agency, but State Lands and BLM and Fish and Game are very involved in that environmental review.

PRESIDING MEMBER LAURIE: I apologize for taking up your time with my questions.

MR. EISENMAN: That's okay.

Going to the next slide, the question was how long does it take to build a pipeline, once it's approved. And again that just depends. I've given a couple of examples here. The two projects that I've mentioned, we're looking at six months for each of those.

However, the pipeline expansion project that PG&E did in the early nineties, running all the way from Canada into Fresno County, that took two years, the construction took two years, but that was a very very significant project.

So, again, it really just depends on how big the project is.

Next slide, please.

The question was, who has the authority to ensure that new natural gas infrastructure is available to meet new powerplant needs at both the federal and state level. And again I want to emphasize that infrastructure additions are really -- pipeline infrastructure additions are driven by the customers and by the market. Certainly there is the regulatory approval. Regulators need to provide pipelines with some incentives.

They are still regulated, both at the state and federal levels, so there needs to be an adequate return. And quite frankly the permitting process can be painful at times and there are plenty of arguments out there that it needs to be expedited and streamlined.

PRESIDING MEMBER LAURIE: Okay. Well, question for you. If the infrastructure additions are market driven, which I understand, then how do you avoid the situation that we are in with powerplant construction, in that the market in California in the early nineties did not promote the construction of new plants and yet it could be argued that the requirement for new megawatts by the year 2000 was known or should have been known.

So in theory, at least, the construction of new power could have been mandated. Is it foreseeable that the construction of new gas infrastructure could be mandated prior to the time that the market would so mandate, but because of longer term need, as opposed to a shorter term market determined need?

MR. EISENMAN: Well, that would certainly be a change from the current regulatory process. I would suspect that at FERC that that would not happen. Perhaps here in California that tends to look at issues much more closely. And given the current situation here, maybe that's something to consider, but I certainly don't see it at the federal level. Plus with financing you do need market commitments of some kind to be able to show potential lenders. And if there was just an order, say from a regulatory body to build without some comfort that a pipeline would recover its costs and that it would be a --

PRESIDING MEMBER LAURIE: No, that's a separate issue to me. I would assume if there's any mandate the cost and financing of such would be addressed at the same time.

MR. EISENMAN: Well, okay. And I would say with my generator hat on, you know, we have made efforts to acquire pipeline capacity. We have capacity on Kern River's first expansion and we are giving consideration to their second expansion and you heard plenty from me in the Otay Mesa proceedings about capacity needs there.

COMMITTEE MEMBER PERNELL: The followup to that, when you're doing the construction or planning construction of the pipeline or going through the FERC for approval, don't you allow for future use? In other words you're building it larger than you need at the time for future use, so that the capacity is not used up by the time you get done with the regulatory process? How does that work?

MR. EISENMAN: Well, pipelines are built with a mix of pipe and compression. And the bigger the pipe is the more compression you'll be able to add later economically.

So you have to kind of strategize about what that mix is. Everything else equal, you want less pipe and more compression, because that's just cheaper to do. But as your question suggests that may not be the best strategy for the longer term, because then you will have to put in a second pipe or add more pipe later which will increase the cost at a later time.

So thinking more globally, you're correct that there are some tendencies to have more pipe and not as much compression the first go-around, so that you can add more compression economically over the years.

And when we built our expansion in the early nineties that's just what we did and we've added some compression since then. And when Kern River was built as a new pipeline nine years ago, it was heavy on pipe and now they're adding the compression and able to keep the rate a little lower.

Next slide, please.

This goes to the next series of questions, is the current interstate natural gas pipeline system adequate to meet powerplant demand on a peak month basis? And the long and short of that, it probably isn't now and it certainly won't be in the coming years.

I think the question then becomes should there be enough pipeline capacity to serve the peak month vis-a-vis storage and so on. And that's something that the market and regulators will need to determine.

As we look at serving peak loads here in California, which for our pipeline, coming from the north, have meant July, August, September and October in recent years, not during the winter, part of the reason for that is the generation demand. And then competing markets off our system north of us and also demand for Alberta gas going to other markets, specifically Chicago and other points in the midwest.

We saw, last year, close to half the days we had to interrupt -- we had to curtail interruptable transportation because there was so much demand on our system, so that leads to a suggestion you need to go expand your pipeline.

And while we're not running at full capacity at Malin at the California border, we are generally running at full capacity upstream because of these incremental demands in the Pacific Northwest.

We also have seen that the differentials on our system have exceeded the tariff rate. That suggests that the value of the capacity is greater than the cost-based rate and also that you should be expanding your system to meet these peak needs in California.

The next slide shows that, in a little detail, our capacity to California is about 1900 a day. Back in '94 we often could deliver up to that, but we've seen new demands off our system. In the Pacific Northwest the Tuscarora pipeline is serving the Reno area and we're seeing a lot of new plants being constructed in the northwest now and these generators are being served or will be served by capacity that, until a few years ago, was capacity that more typically was serving the PG&E system, and we have not added a lot of capacity in recent years.

So, in essence, what we're seeing is a mismatch at Malin between our system, our ability to deliver to PG&E and PG&E's own capacity.

Next slide, please.

Are adequate steps being taken to ensure that gas is available for future generation facilities when the supply is needed? And I guess the answer to that is yes, price signals are working; drilling activity throughout North America is up; the supply potential from the north is very very real.

The next few slides, which I think I'll skip for the matter of time, show some information about supply, and very specifically, going further north, looking out a little to the North Slope of Alaska and the MacKenzie Delta, and on page 18 some pipeline concepts that we're seeing being developed for later this decade to bring gas from much further north.

If we go to page 19, please. That question dealt with which pipelines are currently under consideration to increase capacity to California. We are in an open season right now to expand by 200 a day to alleviate much of that mismatch that I mentioned a moment ago. That open season will end the middle of the next month with an in-service date towards the end of next year.

Mr. Morgan talked about Kern River. El Paso has the All American Pipeline out there. There is some question out there as to whether that will replace existing capacity or will actually add capacity to Southern California. However, nothing that we are aware of is actually under construction as we speak.

Going to the next page, we are looking at a three-phase expansion over the next several years. The first phase is the open season that we're having now. We do believe most of that capacity that will be subscribed, will be from generators or affiliates of generators.

We're also looking at a couple of other projects later in the decade.

The next couple of pages go into a little more detail on our current open season process. On page 23 there are some dates. Again, you'll see the open season concludes on February

15th and it is our intent to file an application at FERC, we hope in April, with an in-service date towards the end of next year.

Going to page 24, please, the question was how much interstate pipeline capacity is dedicated to electric generation. Who are the capacity holders and what happens to that capacity when it's not utilized?

You know, we often don't know where the gas goes. We deliver to wholesale interconnects and there's really no such thing as dedicated capacity. Now our shippers include Crockett Cogen, so I think we can assume that the gas that Crockett Cogen is transporting goes to that facility.

Duke is a customer of ours, Southern is a customer, Reliance is a customer, but the contract name tends to be their marketing companies, rather than the generation company. Are they transporting gas to their generation facilities here in California? Yeah, probably, but what they do day-to-day, we certainly don't know.

And when they're not using the capacity for generation, they may be selling gas to other end users in California, to utilities. They may be releasing capacity.

The North Baja proposal, most of that will be to serve generation in Northern Mexico and, as you know, the Otay Mesa facility. As I mentioned a few minutes ago, with my generator hat on, we manage this very very carefully to make sure that we have adequate firm pipeline capacity to serve our projects in the west.

The next couple of pages show existing and proposed gas-fired generation in the Pacific Northwest, both off our system and off the Northwest Pipeline System and, you know, certainly this, the whole western market, both gas and electric is all one and I wanted to just share that information with you.

Page 27 shows a quick summary of who are our shippers. Again, you see the marketers include affiliates of generators here in California, but the only actual generators who hold capacity are Crockett, SMUD, NCPA and the Cities of Burbank, Glendale and Pasadena.

In conclusion, the supply side of the market, we think, is working. There's always certainly lead times to bring supply on and then to bring new pipelines on. We certainly hope that the regulatory process will be streamlined in coming years, both with respect to siting generation and with respect to siting pipelines.

I also wanted to just remind the Committee about the testimony we provided in the Otay Mesa case with respect to curtailment and curtailment rules, and I'll just leave it at that.

PRESIDING MEMBER LAURIE: Please, if you're going to make reference, make reference to it generically, please.

MR. EISENMAN: Okay. Generically, specifically with respect to San Diego Gas and Electric we do feel that pro rata curtailment is the best curtailment policy.

Thank you.

PRESIDING MEMBER LAURIE: Thank you very much.

One question I'm going to be interested in and I'm not going to ask for a response today, but utilizing my econ up to the 300 series. I was an econ major in college so they made me take statistics. At which time I looked at the catalogue to see what I could do without taking statistics and I ended up being a lawyer, which was the only thing left.

(Laughter.)

PRESIDING MEMBER LAURIE: But I would surmise that as the market sends signals, that will tell you when to expand your infrastructure. Pricing will go up until a decision is made, it is now time to invest. Well, as that price goes up and consumers are impacted by the increase in price, prior to the time that additional capacity is installed, which could lead to lower prices again, there may be a time when the consumer offers political objection to the increase in price, prior to the time that the signals, by the market, indicate that new capacity should be installed.

So the question for regulators, whoever they might be, is should incentives be created in addition, outside of the market, that would provide opportunities for additional growth prior to the time that the market would dictate investments, so as to allow an easier consumer reaction?

Now that hasn't been done in powerplants, obviously, and we have a problem today. But I'm going to have to become a lot more educated on that issue before I understand it better.

Okay. Thank you, Eric, very much.

COMMITTEE MEMBER PERNELL: I have one --

PRESIDING MEMBER LAURIE: Yes, Commissioner Pernell.

COMMITTEE MEMBER PERNELL: -- one question. First of all, does FERC have an expedited review process that you know of?

MR. EISENMAN: FERC has said that they will do everything they can, given the situation in California, to expedite any pipeline certificate applications to California. So, you know, we take them at heart. I'm sure Mr. Morgan took that at heart. That was in a specific order. I can't remember if it was the December 15th order from FERC dealing with the California markets, but it was in one of the recent orders.

So I think the answer to your question with respect to California is, they are very sensitive to the situation now and they will do everything they can to expedite it, but the critical path is the environmental review.

COMMITTEE MEMBER PERNELL: And you will be petitioning them for an expedited review process?

MR. EISENMAN: We've already discussed with them the need to do this as quickly as possible. We've discussed that with the FERC staff as recently as yesterday and we got pretty favorable response that they will do what they can.

PRESIDING MEMBER LAURIE: Thank you, sir.

Mr. Davis, SoCal Gas.

MR. WOOD: Mr. Davis is not here. The next person we would have would be Dan Thomas, Commissioner.

MR. THOMAS: Good morning.

Today I'd like to discuss just some issues around -- I represent PG&E Gas Transmission, California, not the northwest. But I want to give a current overview of our gas system as well as discuss issues around demand, we have seen in our system, and also highlight some issues that we'll use 2005 as an example of issues that we currently face and we have to really resolve. And also highlight some of the expansions that we have at least discussed internally, as well as discussed with certain parties that deliver gas into our system and use our system.

Turning to the map, next slide.

We currently run a backbone, what we call our backbone system which really delivers gas primarily from Malin and in that Topock off of El Paso and Transwestern. We also can deliver small amounts of quantities of gas off Kern Station.

In addition we run, in Northern California, the primary storage field for, primarily used by the core system.

On the right-hand side, I've basically listed the system and also the system capability of how much gas we actually can bring in from the northwest, which is line 400/401, about 1.8 Bcf.

And then from the south, off of Transwestern, El Paso and Kern River, of about 1.1 Bcf per day. And then we also, as I say, own storage fields as well in the center of our market.

Page four. We are the primary backbone transmission, as I indicated, in Northern California. And, a little bit later I'd also like to discuss the need for what we call slack capacity, the notion of having additional capacity available to basically tone down the prices that we have seen for the commodity side of the market.

In addition with respect to our storage fields they're not as large as in Southern California. They primarily were built to serve the core market and that probably represents 80 percent of the storage, a small piece that we actually use for the noncore market, if they choose to use it.

The next page. Again, we provide transportation services. Now with respect to the noncore market, including generation, we do not buy gas supply as a utility anymore for that market. We serve a very small noncore piece and I believe that program ends at the end of March. And so PG&E will be out of the gas supply business for any noncore customer. The only market we will serve is core in small residential.

Most of our large customers are actually connected, just as a backbone or we consider our local transmission system, and so they tend to be large pipe, large diameter pipe that have high reliability of service. With the exception, which I'll be discussing in the afternoon, is the whole issue of curtailments and diversions and the impact on noncore customers, primarily electric generation customers.

The next slide. In the year 2000, just to highlight kind of the loads that we saw, 36 percent of our load was served by the core. But, as you can see, the power market represented 42 percent of our deliveries and almost 998 million cubic feet per day, which is -- we thought it was actually a very good year.

Unfortunately, or fortunately maybe for the gas transmission business, in the year 2001, we probably expect to see that increase because of the hydro situation that we're now seeing in the Pacific Northwest.

PRESIDING MEMBER LAURIE: So in the year 2003 or 4 if you were to put another pie chart, what do you think it would look like?

MR. THOMAS: Well, I'll get to that in a second, because I use 2005 as an example.

PRESIDING MEMBER LAURIE: Good, thank you.

MR. THOMAS: In addition, we also served about 104 Bcf into Southern California off of our system. So we have a large market in Southern California, a large market that people do ship into and help serve.

Now on slide seven, it's somewhat of a very busy slide, but I think it's important to highlight a few issues.

The top line, where you see full capacity, that is basically if our pipe system, coming in from Malin, coming in from Topock is full everyday we can actually bring in roughly a Bcf a day. And what we saw this last year was that the first half of the year, which we also have a seasonal pipeline, because the core tends to use, obviously more gas during the winter and then generally electric generation uses more gas in the summer and in the fall.

And during the first part of the year, that was just a very traditional year that we saw. Demands weren't great, they were just very traditional and we actually had a lot of hydro generation coming into the state from the northwest.

And then in the last half of the year we saw a real change. The hydro was used up and we saw more of a need to have people run their gas fire generation. And so we saw more gas flowing on our system than we had expected.

In addition, you will notice that, in looking at the July-August timeframe, you generally see storage injections, net injections, that time of the year on our system. What we saw was that because of the demand as well as the price of commodity, we saw those people who held storage, such as some of the generators, begin to take gas out of storage, because it was cheaper to use the gas that they had put in storage right then and there, because the forward markets always said that the prices were going to be cheaper. And guess what, they were not.

(Laughter.)

MR. THOMAS: And so we basically have seen increased demand throughout the last half of the year 2000. We don't expect that demand to drop substantially because of -- I say the current hydro generation issues that we face as well as just the increased electrical demand trying to serve California.

Now there's some significant issues that do result from that, that I'll touch upon in the afternoon. But there's issues of serving the generation market. If there are shortages of gas coming into our system, unfortunately the noncore market gets reduced, including electric generation, because there's very very little fuel capability or backup anymore and they rely upon flowing gas supply or gas in storage. And that will be a continuing issue unless action is taken to kind of resolve whether or not there needs to be fuel capability or whether they need to hold, we need to hold storage capability to serve that market.

The issue is going to be what is the economic cost of either electric generation not being there when you need it or the cost of holding backup capability.

Now, turning to the next page, what we have done is taken a look at several cases for gas-fired generation in our market. And I think I mentioned in the year 2000 we were very close to about a Bcf of gas-fired deliveries to electric generation markets in Northern California.

We've taken a look at some cases, taken a look at sensitivity and what we've done is kind of put, what we view as kind of the normal, normal, you know, average hydro conditions, the electric generation meeting, using gas-fired to kind of meet the marginal electric gen requirements. And the high generation case is around 1100 a day, almost 1200 a day, I guess, in our example.

And so we do see, you know, a high gen case. If you have low hydro, in fact, you probably will not have enough capacity or storage in Northern California to meet that market. That, in fact, you will have times potentially, if you don't add facilities, that, in fact, you face the potential of curtailing that market.

In an average year you probably don't have that issue. This also leaves no room, and I think you start to see that, as you move further out you're running a system tighter and tighter. You're not leaving room to basically use storage or flowing capacity for price arbitrage because essentially your system is full or very close to being full everyday, which I don't think really is a situation we want to find ourselves in.

Now, again, this is very preliminary data. We've had -- we'll be looking at some more information. We've had some discussion with CEC on this data and we intend to have more.

Now, what does the future hold -- next page. That we do see the need to have additional backbone capacity to meet the growing demand for electric generation and we need to maintain slack capacity.

In addition, we need new storage to provide services that we believe the market is going to require and need. Now that's great to say, but there's some, I think, real issues around that and if you turn to the next page. While we look at the need for expansions and we can do some things in the near term to add capacity, we also see that we'll have new storage providers, Lodi, late this year, Greg?

It should be on line, hopefully late this year to help provide storage services to the market. In addition, we currently have the Wild Goose facilities in Northern California. And I'll go through some numbers in a few minutes.

The Redwood Path, as we call it, which is really the path bringing gas in from Canada or from the Rocky Mountain PG&E northwest still looks like the most favorable economic decision to make. Unfortunately we have our pipe coming in from the southwest is going to be a very expensive pipe to basically upgrade because of the design, when it was built in 1950.

Now going to page 11, with respect to expansions, we can add on the Redwood Path, a 200-a-day addition for roughly $30 million. The project will take probably around 20 months to do from the time we start to the finish. It's a very inexpensive expansion. It would cost, roughly, around nine cents to install, the capacity. Our current rates are something in the order of 27 cents.

So it's a very cost-effective expansion for our system. In addition, we can add -- with some preliminary looks we can add compression to the system, for another 200 a day and that would cost roughly $90 million, and that averages around 25 cents for the cost of the expansion.

Again, our current rates are less, around 27 cents for firm service. Both of these expansions are then less than what we currently charge our customers.

Now the real issue for this, to do this, it's nice to expand, but unless we see an expansion up north off of PG&E Northwest, this just becomes stranded capacity. And so we need to see what happens with the market that they're attempting to serve and the quicker they expand the quicker we can kind of move forward expanding our own system.

And finally, -- oh, the other point I would make on this also is that, you know, we have a proposal where we could expand our storage fields. We've got Lodi that will be coming on board late this year. Wild Goose will probably want to expand their own storage field at some point in time.

But those expansions also need to come with an expansion of the backbone system, otherwise you're not going to be able to have the capacity to bring gas in, serve customers as well as put gas in the ground. You become limited on your capability to actually flow gas into storage. During this time of year is when you have slack demand and so all of that has to be looked at as we kind of add facilities in our system.

The final slide. With respect to bringing gas in from Topock, really Southwest Gas, we've taken a quick look at that and it would be a very very expensive expansion to do. Because really what it's going to entail is putting pipe in the ground, we can't do it with compression.

And, in addition, we can also add that

we're looking at whether or not we should put more injection into our storage fields, also with raw capacity. And it's something we're exploring currently.

With that, I would just like to highlight that we do believe that, in the long run, actually not very long out, that we are going to have to add capacity and storage to our system to meet demand. I think the biggest variable, obviously is gas-fired generation, how much is going to be built, what is the true need and on the slack capacity should maintain the market, and, finally, who's going to pay for it.

Thank you.

PRESIDING MEMBER LAURIE: Thank you, Dan, very much.

Bill, do you want us to go to Mr. Watson, at this time?

MR. WOOD: Yes.

PRESIDING MEMBER LAURIE: Okay, Steve, thank you.

MR. WATSON: Thank you. My name is Steve Watson. I'm the Capacity Planning Manager for Southern California Gas Company and I'll just speak from notes that I have.

Southern California Gas expects to have sufficient pipeline capacity to serve natural gas-fired powerplants in its service territory, both in the near term and in the longer term.

SoCal Gas has 3500 million cubic feet a day or 3.5 Bcf a day of firm, that's 365 days a year backbone transmission capacity. From 1994 to 1999 the average annual utilization of that capacity was just 75 percent. There is plenty of excess capacity, slack capacity in the system.

Large increases in gas burns by the electrical generators significantly increased that utilization, actually in the second half of last year. Just as with PG&E the first half of 2000 looked fairly normal in terms of utilization rates, but in the second half of the year the utilization of that backbone capacity rose to 93 percent for an average over the year of 87 percent.

And like PG&E, SoCal expects that the annual utilization of its backbone system during 2001 is going to be somewhat higher than in 2000 in that we're going to average over the year over 90 percent utilization of the backbone. That's going to make 2001 a challenging year operationally for the gas company.

But, despite those increases, SoCal Gas does not expect any kind of systemwide curtailments because of two other factors. Its interruptable backbone transmission capacity and its storage capacity.

SoCal Gas often has up to another 200 million a day of interruptable backbone capacity. That's capacity that's available on many days, just not 365 days of the year. It has flowed over 3600 million a day many days this year and it actually flowed over 3700 million a day or 3.7 Bfc yesterday.

In addition to that, SoCal has 105.6 billion cubic feet of storage that can deliver over 3 Bcf a day from its fields during the coldest months.

The noncore customer demand to expand that capacity does not appear, at this time, to be very strong. The existing inventory, for example, was not filled last summer. Mr. Thomas went through some of the reasons for that by noncore customers, even though there was sufficient backbone capacity to allow that to happen during the summer.

So, basically we had 105 billion cubic feet of capacity, but we only reached 70 billion cubic feet of capacity and that was primarily because noncore customers, based on their economics, decided to gamble that flowing supplies during the winter would be a better bet.

Now, together SoCal Gas' transmission and its storage capacity can meet up to a six billion cubic feet of send-out per day during the winter. SoCal Gas actually had a peak send-out day this winter. It happened on January 16th and it was 5. 2 billion cubic feet.

The send-out was met using a combination of 3.6 billion cubic feet of flowing supply, together with 1.6 of storage withdrawals.

PRESIDING MEMBER LAURIE: When you use the term send-out is that synonymous with demand?

MR. WATSON: Demand, burn, yes, sir.

And that demand or burn was comprised of just under 2.3 billion cubic feet of core burn, just over 2 billion cubic feet of electrical generation burn and approximately .9 Bcf of other noncore customer burn.

Now the temperature on that day was 48 degrees, which is actually quite cold for Southern

California. But SoCal Gas believes that it could have met all demand on that same day even if the average temperature had been as cold as 41 degrees.

That's an occurrence which happens only once every ten years or so. That happens to be the level of firm service reliability that we commit to all of our noncore customers, including electrical generation customers.

MS. TOWNSEND-SMITH: And you didn't have to use any interruptable at all?

MR. WATSON: No, we used a little bit of the interruptable backbone capacity was there. It was a cool day which allowed our compressors to pump more gas through the pipes. In addition, we used 1.6 out of that over 3 billion cubic feet of storage withdrawal to meet the peak.

Mr. Thomas referred to it, SoCal Gas has much more storage capability than PG&E does at this time.

The SoCal Gas backbone system is connected to 6 billion cubic feet of potential supply from combinations of sources, El Paso, Transwestern, PGT via Line 401, Wheeler Ridge, Kern, Mojave and California supplies. And planned increases in those systems are going to further enhance supply reliability for Southern California customers, we believe.

Kern River has its expansion plan for 125 million a day. Questar Southern Trails has plans for 90 million to the California border. PGT has mentioned its 200 million and Transwestern and El Paso are considering, although they have nothing definitive on the books yet.

So SoCal Gas could, of course, expand its backbone transmission capacity, but at this point in time it does not immediately appear to SoCal Gas that that's necessary.

Today SoCal Gas represents almost half of that 6.4 billion cubic feet of California burn that Mr. Wood referred to. Our burn was about 3.2 last year.

PRESIDING MEMBER LAURIE: When you look at your demand forecasts, what impact does the movement of new populations in Southern California into the inland areas do to your demand forecast?

MR. WATSON: Well, of course we expect our core demand population to grow by about one percent per year. But of that figure that Mr. Wood referred to, growing to over seven billion cubic feet of total Southern California demand, total California demand, we believe that the gas company or burn on its system is going to comprise less than that.

At this point we are expecting, as seen in our 2000 California gas report, we're expecting that the older on-system electrical generators on our system are going to be displaced by the electrons from the off-system and some of the new on-system electrical generators.

In other words the calculus is not just simply adding up the potential of the various generators, such as in Mr. Morgan's presentation. Not all those plants are going to be built, and when they are built they are going to displace some of the electrons generated by the older less efficient generators.

MS. TOWNSEND-SMITH: So you're counting on efficiency of the new generating plants?

MR. WATSON: I'm just relating, that's what our experts are forecasting in terms of total electrical generation demand on our system. The Energy Commission's year 2000 forecast itself, in its Table Two in the White Paper, basically makes the same prediction that's contained in the

California gas report, total Southern California -- total demand growing in the state, but demand served by Southern California Gas in particular declining.

Nevertheless, we are surprised by the large increases that we're seeing, the high utilization rates. We do not want to be operating -- we would not want to be operating with less than 10 percent excess or slack capacity on a long-term basis, and we're going to continually look at that situation and we may decide to build more excess backbone capacity as a means of encouraging gas on gas competition in Southern California.

And SoCal Gas always remains open to considering expansions to the extent that shippers are willing to pay for them. We have to deal with the experience that we had with our last backbone expansion, which was the Wheeler Ridge expansion. That occurred in the '92-'93 timeframe. The utility was placed at risk for the recovery of the revenues for that investment. It was an incrementally priced expansion, which we supported with shipper commitments and we could continue to do that.

And it wasn't until just last year that the Commission, the California Public Utilities Commission decided to finally roll that into our overall rate structure. But up to that point in time, it was an at-risk incrementally priced facility.

Now, on its backbone transmission system, we don't believe there are any near term constraints on what we call our local transmission system, our redelivery system, the L. A. basin network of pipes. This may change, as you mentioned, Commissioner, as the population in our area, the industry in our area is shifting geographically. And even though we don't expect total demand to increase, the location of that demand may shift within our service territory.

And as new noncore customers locate or expand in particular areas, we have to keep looking at that issue of do we have sufficient capacity to redeliver to noncore customers, including generators.

Now, as was done for the San Diego Gas and Electric system last year, SoCal Gas is going to open seasons this year to solicit noncore customer interest in potential expansions in our redelivery system. That's not in California, but redelivery system in both the Imperial Valley and the San Joaquin Valley local transmission systems.

Open systems, just as in the FERC process described by Mr. Eisenman is the first step in trying to gauge what kind of demand you have and what kind of commitment you can solicit.

We believe that any potential new generator considering siting on any point on our system can be provided the same type of one in ten year firm reliability, firm service, that is currently provided to the existing noncore customers on our system.

The first step in what a generator needs to do to ensure such service is to make a reasonable long-term commitment to the utility to ensure its costs can be recovered and to also ensure the Public Utility Commission of that same thing.

Once that is done and any issues are resolved, and I'm not a permitting expert, I'll defer to Mr. Eisenman, SoCal Gas can construct a new pipeline to the customer's facility within about a year, give or take a few months, depending on the specific situation.

So we don't see a problem on our backbone transmission system. We need to keep looking at it. We don't see a problem on our local transmission system to try to stay ahead of the curve as you had talked about earlier, Commissioner. We are soliciting noncore customer interest for the future via open seasons in the Imperial and San Joaquin Valleys.

Now there is, of course, a well-known constraint affecting electrical generators on the San Diego Gas and Electric system. SoCal Gas has the facilities in place that can deliver almost 800 million a day to San Diego Gas and Electric. But the current San Diego Gas and Electric system can only redeliver, at most, 600 million of that supply to its customers. And this has necessitated small curtailment events for a total of 11 days to San Diego Gas and Electric's noncore customers, including generators during this winter.

But the construction of Line 6900 by SoCal Gas is a low-cost means to provide San Diego Gas and Electric with an additional 70 million of redelivery capacity this summer.

The Baja-Norte pipeline project would

also serve much of the current and potential new electrical generation demands served off the San Diego Gas and Electric system. And together those two projects should eliminate the curtailments currently being experienced by generators in San Diego Gas and Electric's service territory.

Again, I'd be glad to answer questions, but SoCal Gas is always reevaluating capacity situations and whether it is adequate capacity. But at this time there's no evidence that the SoCal Gas system is constraining natural gas-fired electrical generation. There have been no curtailments of either firm or interruptable noncore customers on our system for over ten years. And by committing to the Line 6900 expansion, I believe that San Diego is taking aggressive steps to ensure reliable service on its system.

Thank you.

PRESIDING MEMBER LAURIE: Thank you, sir, very much.

MR. TOMASHEFSKY: I've got a quick question actually. I understand the concept that the system itself is not constrained, but there's different -- when you start to look at takeaway capacity at the border, one of the constraints that we've discussed before is SoCal Gas delivery at Topock into the northern part of the SoCal system, which, in essence, doesn't constraint what can go into the system, because there are other ways of getting the gas into California. But doesn't that create some logistical problems in terms of serving load, at least from a longer-term standpoint. It doesn't give you as many options for delivering gas to, or perhaps obtaining your preferred supply alternative.

MR. WATSON: From an operational perspective it doesn't constrain us in terms of serving the customers. I believe that the issue with Topock is more of a price trying to deliver cost of gas supply issue for the shippers trying to serve end users. That Topock, over several years has been one of the lowest priced delivered cost points on our system and customers would like to have more of that supply and there are usually more nominations for supply there than we have take-away capacity.

But the supplies at Topock also have other potential outlets. There is the PG&E market. There is EOR market, via Mojave. It is true that there's a lot of upstream capacity from the San Juan Basin to Topock, but Southern California Gas is not the only potential outlet for upstream capacity, there are other markets for it.

PRESIDING MEMBER LAURIE: Thank you very much.

MR. WATSON: But I do think, Commissioner, just to follow up, I do think that that's -- in terms of making expansion decisions or thinking about expansions, I should point out that we have many potential points to think about expanding, if we were to expand. Wheeler Ridge was mentioned by another panelist. Topock is often mentioned as an alternative to consider and if you talked to California producers, they would say that we should expand to California producers to give them more access.

So the issue of -- there's two issues to decide. First, is an expansion warranted. Two, can the cost of the expansion be recovered and three, expansion to where?

MR. TOMASHEFSKY: So from a systemwide perspective one of the intuitive things that you can look at is that there's more delivery capacity to the state than take-away capacity from the border. And what you're suggesting is that you could, not necessarily SoCal Gas, but you could increase take-away capacity. Topock doesn't necessarily have to come from SoCal Gas, but it would be a relatively quicker fix to balance out delivery and receipt capacity for the California market itself, as opposed to one particular pipeline company and how that works.

Because if you do have excess capacity going into Line 300 and you don't have the additional take-away capacity at Topock, you could satisfy that need by expanding capacity on say Mojave, PG&E or SoCal Gas.

MR. WATSON: Right, and I do want to give the impression we do have the ability to expand the Topock system. That expansion, like PG&E's Line 300 expansion would be, potentially, fairly expensive relative to some other points. But we could expand any of our backbone points and we'll continually look at that, but there doesn't seem to be an immediate need to do so, but we're always open to talking to shippers about such expansions.

PRESIDING MEMBER LAURIE: Thank you very

much.

Just a quick note, those speakers that do have written comments, we have to make sure that a copy of such gets to Mr. Buell, so that our record can be made complete. And also we are going to have time for public comment following the presentation by the speakers.

Mr. Chancellor, good afternoon, sir.

MR. CHANCELLOR: My name is Craig Chancellor. I'm with Calpine and I've got, like Mr. Eisenman here, a couple of hats on.

One is as a consumer of gas. And I'd like to say that Calpine, in its siting process, certainly does consider the gas supply and the economics.

Calpine, as I was stating in its process, does consider the availability of both the supply and the transmission capacity to meet our needs. Calpine is confident that the market will react to the needs of electric generators and other industrial and core customers.

If you look at the supply chain and the process that's occurred, we've heard that the drilling is up in the various basins. That's been a reaction to the market price of natural gas.

You also have heard from the interstates that they are considering expansions. Some of those have already been formalized. Calpine is participating in those expansion processes.

You've heard the intrastate mention their consideration of expansions and we're involved in those discussions also. So we feel that the market will react to that. Each one of these paths along the supply chain can have constraints and that can be, like say, depending on whether it's the gathering within the production area all the way down through to the intrastate system with the backbone and local transmission.

Calpine is taking a somewhat different approach maybe than some other generators in securing its gas needs. We are taking more of an approach that will balance our portfolio of gas needs with a certain amount of firm capacity, not only on the intrastate system, but interstate all the way up through the supply basin. Also acquiring our own gas reserves and production that would be dedicated to our facilities.

When you get through that process, you know there's a lot of things to consider and I think the White Paper has done a good job of that. There are some things that weren't brought out that are maybe some other alternatives, such as LNG facilities. I know some of those are being discussed and considered in other markets.

I think you've seen some LNG facilities that have been brought out of mothball and have increased production and filings made to expand the production of LNG, so that's another alternative that can be explored for meeting gas demand here in California.

You've also seen an increase in storage being provided. Mr. Thomas mentioned Lodi Gas Storage, Wild Goose is already in operation. Lodi Gas Storage will be coming on in October of this year is the current plan, so we see the flexibility of the intrastate system increasing from these storage providers, and we plan on utilizing those facilities.

With that said, one thing that has not been discussed too much, Steve mentioned it a little bit, was the local production area. I think currently local production makes up about 15 percent of the market, but there's more closer to like four tcf of reserves on land reserves that can still be utilized.

Some of the uses associated with maximizing that production is the quality of the gas, the Btu heating content. There are constraints associated with the pipelines of how much they can take of that because their customer demand has to be maintained at a certain specification.

Calpine is taking the approach of investigating and investing in local facilities to optimize the local production.

Some of the constraints, like I said, associated with that is the MMBtu quality, the heating value, and that local production cannot meet all of the demand. So one way to enhance that is a blending process to take the higher MMBtu quality gas from the interstate system and bring it in and mix it and blend it with local production to optimize that. And there needs to be incentives, I think, for the development of that sort of capital infrastructure to achieve that.

As far as the ability of these pipelines and the market to react, I think that you had asked the question about the timing of that. One side benefit of the siting process, even though I'm not sitting here advocating that it be longer, is that given where its at, there's usually at least two years or more of known facts of when a plant is going to be coming on line. It gives the market time to react on the gas side, which I think is something that's a positive and allows that to occur.

I don't have a prepared presentation, but I'm here to answer your questions and allow people to go to lunch a little earlier.

PRESIDING MEMBER LAURIE: And thank you, sir, very much.

At this time we'd like to open the forum up to the public for questions or comments. One thing, I will not permit specific questions on current siting cases. You can speak generically, but we're not going to create any kind of side evidentiary record on ongoing siting cases. And I would thus ask you not to raise such questions.

Okay. Mr. Williams. Those folks that are approaching the microphone, please state your name for the record, please.

MR. WILLIAMS: Thank you, Commissioner Laurie. I'm a retired engineer with 35 years' experience in the electric power business, but essentially zero experience with natural gas.

I have two questions. The first is a little complicated. In your opinion, to any of the members of the panel, what is the effect, if any, of OPEC price signals on the price of natural gas, and to the extent that these signals might artificially depress prices. For example, $12 a barrel for oil would be $2 a million Btu for natural gas. Do these delay the construction of necessary pipelines? I therefore suggest that the CEC establish requirements for other construction.

And my second question relates to the price elasticity of demand of natural gas. In the short term and in the long term if you would double the price of natural gas, in your estimation, how much would the demand increase?

PRESIDING MEMBER LAURIE: Good questions. Thank you, sir.

We have two questions. One relates to OPEC and its impact on natural gas pricing. And the other relates to elasticity.

Who would like to respond?

MR. THOMAS: I'll take the first one.

Mr. Thomas, yes, sir.

MR. THOMAS: Personally, I don't believe OPEC --

PRESIDING MEMBER LAURIE: Let's, again, for the record, before you speak, identify who you are, please.

MR. THOMAS: This is Dan Thomas.

With respect to the question and I guess on prices, I guess it's been my experience that, you know, even with these runup in prices of oil, the influence is on the drilling activity for oil. And gas basically gets the advantage of it, because then gas comes along with it, and so a lot of the Canadian production tends to -- if you're going to spend money you're going to spend it on oil drilling, and gas is kind of a secondary matter.

PRESIDING MEMBER LAURIE: Is that always the case, almost always the case --

MR. THOMAS: No, it's not always the case, but you see a lot of the companies with their exploration budgets tend to be big players heavily invested in oil, and so I think we benefit basically from having more of the product on the market. And if you have more gas commodity then, I think, that helps both the growth in the natural gas business but also just the pricing itself.

PRESIDING MEMBER LAURIE: Thank you.

Any -- yes --

MR. CHANCELLOR: Yes, this is Craig Chancellor, Calpine.

What Mr. Thomas said is true, there's associated gas and nonassociated gas. Most of the production, I believe, in Northern California is nonassociated with -- I think in Southern California it tends to be more associated with the oil production.

Another impact that oil prices have on natural gas is the alternative fuel issue, where the fuel oil consumption acts, and the price of that acts as a cap on the natural gas price. So as that fuel oil price goes up, the use of natural gas would be preferred over fuel oil and as that drops people will switch back and forth. So there is an interplay between the switching back between fuel oil and natural gas that has an effect on the price.

PRESIDING MEMBER LAURIE: Thank you, sir.

Anybody like to comment on elasticity of price?

All of you who managed to get through statistics.

(Laughter.)

PRESIDING MEMBER LAURIE: Nobody has any sense of response to pricing?

Bill, do you have any thoughts?

MR. WOOD: Well, I'm more of a supply side person than a demand side, so I would anticipate that if prices did go up that, to some extent, the demand might respond by dropping slightly. But, on the other hand, if we're looking at the residential, commercial operations of, for instance, in space heating we've got dedicated furnaces already in place and appliances. And, for the most part, the only price response there as an opportunity here would be here to reduce the thermostat, so to speak, and therefore reduce demand.

Now, whether people will actually do that or not I guess has actually occurred in San Diego where they reduced some of their electric demand in the summertime as a result of the high prices that they experienced earlier this year.

But in California in some instances alternative fuel is not an option. And so, therefore, in California, more than likely, the gas demand will continue to be there.

For instance we saw prices in December hit $60 a million Btu. And our gas demand still was being satisfied and probably a lot of that high-priced gas is going for electric generation, so the price was still being passed through. So a corollary or a subparallel question to be asked along with this particular response would be who was going to be paying for that -- who is paying for that price and if it's an industrial or commercial establishment or electric generation, to what extent can they pass that on in their product or roll it in with another supply that might be available to them that would be lower cost?

PRESIDING MEMBER LAURIE: Thank you.

I do have some blue cards.

Mr. Chancellor, go ahead.

MR. CHANCELLOR: This is Craig Chancellor with Calpine. I can make a few general comments.

As far as some of our electric facilities, depending on the price of gas and what the price of power is that sparks spread, you will see a diminishment of that. An example, one of our cogens may have a heat rate of around 13 hundred versus say a newer efficient one of 7,000.

When gas prices $11, $12 it became uneconomic when the price was set at 150. So there is some elasticity on that. So it's always going to depend on your alternatives associated with that use.

Mr. Wood mentioned the fact that, you know, once you have some of the core load already on gas versus electric and they can't switch back and forth between fuel uses, the other alternative is either to turn your thermostat down or turn your process off that you could just continue using that.

So I think the gas market is much more elastic than the electric at this point, because of the structure that's set up. Those prices are passed on to consumers at this point, and as these gas bills come up people will turn their thermostat.

PRESIDING MEMBER LAURIE: Thank you, sir.

We do have some blue cards and I will

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call upon those folks. It's somewhat helpful, if you want to comment, to fill out the cards, although not fatal if you don't.

Mr. Moore, good morning, sir.

MR. MOORE: Good morning.

PRESIDING MEMBER LAURIE: And you're going to comment on San Diego recognizing that the PUC is conducting a thorough examination of San Diego gas supplies.

MR. MOORE: Right. My name is Steven Moore. I'm with the San Diego County Air Pollution Control District.

I just want to comment on something Mr. Watson said as far as the potential for curtailments in San Diego County of the gas supply. In our view the reason for the curtailments is that SDG&E just recently began selling 70 million cubic feet per day or at least that amount, up to that amount, to -- they have a powerplant at Rosarita Beach.

And it's true the Line 6900 would potentially cover that amount. However our best information is that there's an additional 85 million cubic feet per day up to that amount that will be sold to Rosarita Beach this summer, and hence we see that there's a significant possibility of additional curtailments in San Diego County.

PRESIDING MEMBER LAURIE: Thank you, sir.

Mr. Martini.

MR. MARTINI: Good afternoon, Mr. Commissioner, my name is John Martini. I represent the California Independent Petroleum Association. We represent independent producers of oil and natural gas throughout the state and have about 450 members representing producers, supply companies, representing about 90 percent of the oil and gas producers, independent oil and gas producers in the state.

I want to make a couple of quick comments. We'll be filing a letter with extended information to the Commissioners and the Committee. I appreciate the opportunity to comment.

I just wanted to add that from our membership's perspective we see California producers as being in a unique position in terms of the supply that we have available to be a contributor to helping resolve the supply concerns that we're here to discuss today.

As was referenced earlier, the Division of Oil and Gas was estimating that we have approximately up to four trillion feet of approved reserves on shore in California. That's in addition to the 21 trillion cubic feet of approved reserves that we have along the Pacific coast offshore in both state and federal waters.

Some of the issues that we'll be talking about and the comments that we'll be filing, in regards to our ability to increase and to increase the amount of gas that we're supplying to the pipeline system, our issues primarily revolve around ability to have access to the pipelines, time it takes to achieve connections.

We also have a substantial number of issues relative to the utilization or the gathering system. As was referenced earlier, right now California in-state production accounts for anywhere between ten to fifteen percent of the total state's needs. Historically that number has been as high as 20 to 22 percent.

The California Independent Petroleum Association will be commissioning within the next couple of weeks a gas elasticity study that we'll be happy to share with the Commission once we've completed that. They'll be looking at the full range of issues.

Our feeling and contention is obviously that with the substantial amount of crude reserves here essentially in our backyard, that we do have the capability and ability, given some of the proper incentives and regulatory relief to begin contributing to some of the increased supplies that will be needed to assist with the future power siting and etcetera.

PRESIDING MEMBER LAURIE: Thank you, John, very much.

Will you provide a card to the reporter, please. And where are you located?

MR. MARTINI: California Independent Petroleum Association is located here in Sacramento on I Street. I believe my address is on the card. I'll be happy to provide a card to Mr. Buell or Mr. Wood. I know Mr. Wood has my phone number.

PRESIDING MEMBER LAURIE: Thank you very much.

MR. MARTINI: Thank you.

MS. TOWNSEND-SMITH: What's your

deadline for your study?

MR. MARTINI: I'm sorry?

MS. TOWNSEND-SMITH: When is your study supposed to be completed?

MR. MARTINI: We put out the bids yesterday. We expect to have it completed within the next two to three weeks. We've already actually contracted with a consultant.

MS. TOWNSEND-SMITH: Thank you.

PRESIDING MEMBER LAURIE: Mr. Brunelle. Good morning, sir.

MR. BRUNELLE: Good afternoon. My name is Barry Brunelle with Sacramento Municipal Utility District. And I think my question is probably going to be directed to Mr. Chancellor here. Hi, Craig.

(Laughter.)

MR. BRUNELLE: We've seen from PG&E that the amount of increased capacity that's sort of on the table is perhaps 400 million cubic feet a day, and it would be very problematic to expand the Baja path.

You have a lot of capacity. You're sort of representing the generation company that's up here right now that's coming on line. Are you

contemplating, perhaps, something like a Mojave
Northwood expansion or some sort of intrastate
expansion, yourself?

MR. CHANCELLOR: We have had discussions with some interstate pipelines considering expansion. Nothing is concrete or has come of that as of yet. I think, you know depending on where the market goes, that's still a viable issue.

Our own propriety pipeline system, we are continuing to optimize it. We don't have any plans for a major expansion at this point, but we will move it out to where additional production comes on line and continue to tie these disparate pipes that we have together physically to be able to move gas between our various facilities.

MR. BRUNELLE: Okay, thank you.

PRESIDING MEMBER LAURIE: Thank you.

Mr. Akaba. Good afternoon, sir.

MR. AKABA: Good afternoon. My name is Azibuike Akaba with the Communities for a Better Environment.

I've got a couple questions, more about qualitative aspects of the natural gas.

Given the potential shortage of natural

gas, does that mean that California is going to change the standard on what the variability of the natural gas, like in terms of quality? Especially I'm more interested in like the sulphur content, like is there a standard that you will have for natural gas?

PRESIDING MEMBER LAURIE: Okay. Let's stop there and see if anybody is in a position to respond to your question.

Gentlemen, do you have any thoughts? First of all, is the question understood? Anybody have any thoughts about it?

MR. WATSON: The gas company doesn't think it's necessary to compromise pipeline quality specs in terms of getting adequate supplies. The issue, for example, of sulphur was one issue we are about to have -- in fact we actually are beginning to flow supplies into our system from Oxydental's supplies in the Elk Hills, ensuring quality control. Blending procedures to make sure that quality specs are met is something that was addressed in that interconnected agreement.

So I'm not an expert on the quality issues, but I know that we think you can maintain quality and accept additional supplies and Oxydental is a good example of that.

PRESIDING MEMBER LAURIE: Do you have another question, sir?

MR. AKABA: Yes, sir.

And are there any existing regulatory priorities for who gets the gas in case there's a shortage, like --

PRESIDING MEMBER LAURIE: I think we're going to be talking about that this afternoon.

MR. AKABA: Okay.

PRESIDING MEMBER LAURIE: Is that right?

MR. WOOD: That's correct.

PRESIDING MEMBER LAURIE: That's the whole issue of curtailment.

Thank you, sir.

Anybody else, question or comment?

Thank you. Very well done, gentlemen. We appreciate it very much. We'll reconvene at 1:15.

(Thereupon the lunch recess was taken.)

AFTERNOON SESSION

PRESIDING MEMBER LAURIE: Mr. Thomas, Mr. Seedal, are you folks ready to go?

The issue this afternoon is a discussion of curtailment policies and procedures. Part of our panel is present and ready to go. Dan Thomas from PG&E and Mark Seedal from Duke.

Mr. Thomas, are you ready to offer your comments at this time, sir?

MR. THOMAS: Thank you. What I'll do is we'll walk through PG&E's current curtailment policy and what is embedded in our existing tariffs.

The drivers for curtailments of any customer really depends on gas demand and available supply and existing storage. Generally you see a high gas demand day and that's where you would see issues around curtailments or diversions that might be necessary to meet residential needs.

Generally you see extreme cold weather core demands and you see -- often you might even see extreme demand for gas-fired generation without the matching supply.

Probably the last time we had a measured curtailment was back in the early nineties where, in fact, we, during the winter turned the plants that we owned at the time to oil-fired generation and we burnt almost one Bcf a day of equivalent oil. I have not seen that since the early nineties.

The second major reason for curtailment would be a loss of supply. Often you might have a pipeline outage somewhere, whether it's on the interstate such as we saw with El Paso this last summer with that explosion. Or you might see, in the case we actually had curtailed customers in Santa Cruz a couple of years back, because we had a slide that actually took out a pipeline. Or you could see our capacity shortages occur.

On page three, just looking at kind of a simple supply demand picture. And what we do is look at our demand overall and we go from kind of an average day. In our system it's around 48 degrees and you kind of take a look at different scenarios and how we build our system.

And a cold winter day is defined of kind of a one in four year event and that's 38 degree system average, down to an APD day, which is around 29 degrees. It's the coldest we've seen in our system. And what you see, you move from left to right and you have to look at your core demand, your increasing. Your overall demand might be increasing and then you take a look at your supply and you have to figure out where it is.

And on the left-hand side, if you look at supply in that picture what we have is the two interstate pipelines serving us, the major interstate pipelines serving us full and we're taking gas out of storage at a max level.

Now, as demand increases, you eventually reach a point where you don't have enough capacity or storage and flowing supply to meet all of your demands on a system, and you eventually reach a point where you have to curtail noncore and potentially even divert gas supply to serve the residential market.

And the tariffs that we have with the state commission actually envision this type of scenario.

Page four, our operating objectives are very simple. You know, maintain a safe controlled operation of the pipeline system, protect core end users, if at all possible. They'll basically be the last off the system. So we do everything we can to serve all customers, but primarily we have to make sure that the residential customers are not turned off. And we operate within the parameters of what we call Rule 14 at the state commission and it imposes certain obligations on us and certain requirements to go through a process to potentially either divert gas or curtail customers.

And we've had these rules in place since about 1997, actually implemented them in 1998.

Page five, we have four different system protection levels as we call them. And the first one is what we call an operational flow order, and I'll go through those. And the second, emergency flow order and then involuntary diversions, where we actually do confiscate gas. And then lastly, you start to basically turn customers off to protect the system.

And you could actually reach a point, if you don't have enough flow-in supply, you're actually curtailing potentially even residential consumers in certain areas of our system.

Page six, what is operational flow order. Each and every day we look at our system and we require that customers, marketers, brokers in some cases even end users who hold backbone capacity to stay within a given tolerance level and it's fairly liberal. But we look at our pipeline system and we need to make sure we stay within certain inventory levels on the pipeline, certain pressure levels. And if we fall outside of those or if we see that we're going to fall outside of them in a few days, basically we will call an OFO, Operation Flow Order.

First of all we look at who are those customers that are causing the problem and if we can identify two, three, four, five customers, we basically call that flow on them first. Let's see if they can't get back in balance.

If they don't get back in balance then we call on the entire system, so we can kind of maintain a certain level of flowing supply, certain inventory pressures on the system.

And if they don't get back in compliance or are not in compliance then there's a penalty. And depending on kind of what we call, what stage of a penalty it could range anywhere from 25 cents all the way up to $25 per decatherm. So it's a pretty hefty incentive to get back in balance.

I should say also on OFO, these have been called I would say rather frequently. They do occur. They occurred more in 1998 than they have in 1997 -- rather in 1999 or 2000 because we've been working with our customers to basically improve the process that we go through, but this does still occur.

PRESIDING MEMBER LAURIE: And when you say it's issued, it's issued by the utility?

MR. THOMAS: Yes, it's issued by the utility, that's correct.

The second feature of this, or if we found ourselves in shortages is what we call an EFO or an Emergency Flow Order. And there if we see a problem we would require that customers exactly match their burns that day. And so this is kind of an extreme provision and I think we've used it once in the last three years. So it is used, but it's rarely used.

And if you're not exactly bringing in the gas supply to match what you use there is a $50 penalty involved in that. So again, it's very penalty oriented and we basically want the gas to come in to ensure that everybody's supporting themselves. And it's only used when there's kind of a supply shortage. It's not used when more gas is being delivered to the system. In those cases that's fine.

The next feature or next part of the general process is what we call involuntary diversions, and it's used when the core market supplies are insufficient to meet the forecasted demand.

As an example, in our own systems our co-procurement buys gas primarily from two basins, Canada and in the southwest. And if you have any weather issues, let's say out of Canada, well freeze-ups, you know, an arctic front comes through, potentially they could be short of natural gas.

If they can't make it up with storage inventories that we have, we basically then would have to turn to involuntary diversions and we would essentially then turn to the noncore customers and essentially set a level that we can let them burn. But what we're really doing is kind of taking the gas from them. Some of the gas, maybe ten percent of what they might be using, five percent, twenty percent of what they would be using on a normal day, taking that away from them to serve the residential and small commercial customers.

And in this case, if we divert the gas then there's a $50 charge that our core customers pay and then that payment is then made to the party that we diverted the gas supply from.

I'll use the powerplants as an example. If we diverted ten a day from the powerplants they would actually receive a payment of $50 per decatherm for that gas that was diverted.

MR. WOOD: Dan, can I ask you just a question here?

MR. THOMAS: Sure.

MR. WOOD: That $50 per decatherm, though, is only applicable to firm capacity?

MR. THOMAS: That's correct.

MR. WOOD: And if it's not firm capacity that you take it would be --

MR. THOMAS: If it's not firm capacity then what our core would be essentially, it's like a weighted average price, kind of an index price.

MR. WOOD: So it would be kind of like a border price.

MR. THOMAS: Yeah, more of a border price.

MR. WOOD: And if you were to pull gas or involuntarily divert that you would probably divert that as available, if there's any of that available?

MR. THOMAS: Right and I'll go through the kind of sequence of steps, but, yes.

Then the next slide is a sequence of diversions, page eight. As Bill said, first of all, what we do if we see a problem, essentially any as available customer or contract rather is cut, and that's both on and off system.

In our system we've gone to more of a city-gape system for end users. And if you hold back on capacity, you can hold firm capacity or you can hold as available or interruptable.

PRESIDING MEMBER LAURIE: And is this pursuant to PUC order?

MR. THOMAS: Yes, this is pursuant to a settlement that we had with our customers, end users, marketers, brokers, that the Commission essentially adopted in 1997.

PRESIDING MEMBER LAURIE: And it's unique to PG&E?

MR. THOMAS: It's unique to PG&E.

PRESIDING MEMBER LAURIE: Are the rules in the settlement as set forth and as utilized today still current, any discussion about modification, to the extent that you know about?

MR. THOMAS: The current rules and the agreement that we had that was put in place, essentially, unless extended by the Commission would end at the end of 2002. I can't go into the details, but we have actually started discussions with settling parties to kind of redo the whole system, or if that's what they want to do, we'll go there.

But once you take the as available shippers off you then go to those customers who hold firm gas contracts or firm transportation agreements and you start to take on a prorata basis the supplies from each one of those contracts. Obviously that then is impacting the induced market.

And then lastly we would take gas that's in storage that somebody might have as an as available contract, we would actually end up taking that gas from that party.

And that's the general sequence that we would go through. We've never done this and hopefully we never will, but that is the sequence.

Slide ten.

Just very quickly, if a customer does

not comply, a noncore customer does not comply then we would essentially temporarily shut them off from gas service to ensure that compliance did take place.

And the last point is there's always a question whether or not these noncompliance charges that we currently have, do they really provide the incentive for a customer to shut down. I think we saw some of the prices, I think it was back in either November or December. I'm not sure that any penalty that we had in place would have shut generation down based on some of those prices.

So we hope that they comply. If they don't, then basically we would -- we have the ability to basically turn gas off to these customers, including the power generators.

On page 11, there are a number of issues with the noncore market, obviously on curtailments. But the bottomline is that while the market has accepted this, they are no longer required in most cases to maintain any backup fuel capability. There are some customers who have maintained it, such as glass companies, but that's kind of an economic decision, because obviously they do get cut. They have a lot of issues around furnaces that they try to protect themselves from so they actually do maintain it. But by and large noncore customers do not, or do not have backup fuel capability, and that includes the majority of the electric generation market in our market.

On page 12, this is the kind of the demand that we saw in the year 2000 broken into two segments. And this is just the noncore market broken out between electric generation and the balance of the industrial large commercial load. And you can see that the electric gen is a significant portion of our market and any curtailments that do occur, they are hit, and that's just the process.

We would go through a prorata basis pretty much because most of these would probably have firm contracts that they would be operating within. And so if you see a cut, electric gen is going to get cut as well.

Page 13, what you would see obviously is if you started to cut your gas-fired electric generation, today you would essentially see reduced electric generation output and that would essentially directly impact the generation that is really serving our market, because they don't have backup capability for the most part and there is obviously the question about the ability to replace that electric generation that would be lost.

Page 14, from a customer's perspective, you would essentially start to see electric blackouts occur. And obviously when you start to have blackouts it's affecting everybody. If you're lucky not to be on a rolling outage I guess you're not affected. But for the most part you're starting to affect residential consumers with blackouts on the electric, and which then starts to counteract the effect of these diversions to maintain core service, because without power to the house your gas furnace will not run.

PRESIDING MEMBER LAURIE: Mr. Thomas, let me be rude here for a moment. I have to have about a 30-second conversation with my Executive Director and I need to hear what you have to say, so let's go off line for about 30 seconds.

(Thereupon a recess was taken.)

MR. THOMAS: Just lastly, as I said, any curtailment of gas to electric generation could have a very negative impact on electric output serving the residential markets.

Slide 15, options to avoid curtailments. Obviously finding additional peaking supplies and it will help with Lodi coming on line. In addition, if we or Wild Goose were to expand storage facilities that should help as well. Though, to really fully implement some of these storage expansions we also then have to look at kind of our central backbone system and probably add some reinforcements to that, and it's something that we would undertake.

Secondly, it's just the whole issue of alternative fuel capability for noncore customers and obviously that would mitigate the impact of diversions.

Now when we talk about alternative fuel, I think Bill mentioned today some kind of fuel oil capability. It may be questionable whether that's really doable in California and storage options may be the best thing to look at, those who take time to put in place. And obviously just the whole issue of conservation and that conservation that we starting to I believe see on the gas side. Because of these high bills it will be kind of interesting to look at over the winter to see what actually has occurred and to see how this gas conservation is happening because of the gas prices to the residential consumer.

And anything we do obviously you have to look at the economics and the cost benefit ratio of doing those.

PRESIDING MEMBER LAURIE: Is the economics of providing peaking supply the same as the economics of providing peaking electricity supply? Is that an understandable question?

MR. THOMAS: Oh, yeah. The question becomes, I guess when you look at the economics, at least from a gas perspective and I'll try to take it to an electric perspective, is first of all, can you replace the electric generations you lost? If you can, then you probably don't need to do anything to the gas system to avoid that.

The question becomes, on the electric side, when you do curtail somebody I suspect there's two impacts that are happening. One is that the remaining power, if it's sold on the spot market, goes up to basically whatever your caps are, assuming there are caps.

And then secondly, what is the lost production that might occur with other noncore customers or residential customers as you turn them off. So I'm not sure it's a real simple question, or simple answer I should say.

Finally, I guess really in conclusion, I do think as we kind of go down the road, because I mentioned earlier this morning, that while we have some capacity that's not being utilized today, we are getting the situation where something needs to happen in our system to ensure that there is enough capacity to serve the market.

We need to look at storage options and we do need to address the issue of who is turned off in the event of a curtailment activity. Our system is not designed to serve every customer each and every day. I think probably most people familiar with our -- we did have a curtailment back in 1998. It affected mostly the Sacramento Valley. Because of the cold weather, we actually fell below, actually got close to an APD day, I believe, in the Sacramento Valley region, and we did turn noncore customers off, including some small cogenerators. And I do remember the conversations that were being had with the ISO at the time and they were very concerned that, in fact, the generation, small as it was, was actually cut back at that point in time.

So it's an issue that we continue to bring up and it's an issue that has to be addressed in the long run.

And that's it.

PRESIDING MEMBER LAURIE: Thank you, Mr. Thomas, very much.

Mr. Seedal from Duke. Good afternoon, Mark.

MR. SEEDAL: Yes, good afternoon. My name is Mark Seedal. I'm Duke's Director of Electric Modernization. Duke Energy owns the Moss Landing, Morro Bay and Oakland Powerplants up in Northern California and it operates the South Bay Facility down in San Diego.

Just to give you an idea, the powerplants we have up in the state use about 31 million cubic feet an hour at maximum gas input and that translates to about 3200 megawatts. The Oakland powerplant, by the way, burns fuel oil, jet fuel, about 330 barrels an hour at maximum output.

And just to give you an idea of how that might transform, which I think is of interest, if we were to modernize all those facilities, which is our hope and intention, over the next number of years, we would see our gas loads go from, roughly, 31 million cubic feet an hour to 36 million cubic feet an hour. Yet, the generation output would go from 3200 megawatts, roughly, to 4700 megawatts so you can see some rather positive benefits of fuel economy, while the load does go up a little bit on the gas side, roughly, you know, ten, fifteen percent. The electric output goes up 40 to 50 percent, so just as a way of background in thinking about future projections on the demand side.

In terms of our thinking on supply and pipeline capacity for our powerplants, it is essential before we plan a significant investment in a major powerplant modernization or greenfield site that we have sufficient natural gas capacity, supply, distribution system capacity, transmission capacity, backbone capacity to support that powerplant. You just simply cannot invest a quarter million, a quarter billion dollars or half a billion dollars in a new facility and not have enough fuel to run it. That isn't good business and we don't plan that way.

So just in terms of how we think before

we start a project that's fundamental to our thinking.

In terms of the local gas utilities, it's our view that they need to beef up their local distribution, including gas storage to fully serve the core demands at a minimum in others as deemed appropriate under reasonable adverse conditions and to have adequate capacity, under probably those same reasonable adverse conditions, to serve electric generating loads.

And I guess I think it's important that some thought be given to what are those adverse conditions and what kind of planning goes into defining those adverse conditions, that's very important. And probably you need to recognize the cold weather conditions in the winter, that there be adequate pipeline capacity for this core and other gas usage as well as electric usage that must be served. And I want to note here that Moss Landing, for example, South Bay and our Oakland facility are all must run electric facilities, so it's another dimension to the ISO's planning in terms of their expectation on the output from those plants.

So thought needs to be given to what

resources are needed from both a gas side on an adverse day, as well as an electric side. And that electric side now probably has to take into account a summer peak for electric loads, as well as having sufficient pipeline capacity, I think, to ensure storage can be adequately filled, especially if what I've been hearing so far today is that there's going to be some hopeful expansion of gas storage injection capability and the like, so that we can make more efficient use of the gas pipeline system that exists, both in the summertime and in the winter.

So gas supply planning and how we define these adverse days is of vital importance.

Secondly, we are of the view that powerplants in California really cannot be expected to burn alternate fuels, given current air regulations. By and large, you know, Moss Landing, Morro Bay both had previously alternate fuel burning capability. Those have been discontinued. The only site we have left is South Bay, which has the alternative fuel burning capability.

It's quite controversial with the air district, so, you know, our view is -- and when we look forward in terms of new plants and projects we know that there aren't enough air permits to allow us to permit a plant in a reasonable way with alternate fuel burning capabilities so we need to rely on gas.

So the future consideration for planning must take into account there's going to be very little, if any alternative fuel burning capability. And if there is remaining alternative fuel burning capability at some of the existing powerplants, which is mainly being used to support core gas loads under adverse conditions and those plants have been in existence for some time paying their long-term distribution fees, there may be some thought that has to be given for the gas companies to compensate the electric companies for having that service available to support the gas system under adverse conditions.

PRESIDING MEMBER LAURIE: Putting aside for a moment the question of air emission standards, if you assume, for purposes of discussion, that the requirement of an alternative fuel capability is good and proper planning, assuming that for discussion, generically can you give me the parameters of what kind of additional

costs your typical plants would incur today if you
were to provide an alternative fuel backup?
MR. SEEDAL: I don't have a sense of that. Actually you have to think about there is, you know, the gas storage -- the oil storage capacity, you know, on site, the oil inventory carrying costs that has to remain on site, the heat that has to be used to keep the oil ready to move, the equipment that has to be available.
I also want to point out that there is a risk element of converting to alternative fuels or to fuel oil in that we have to ramp it down somewhat to exchange the nozzles for the fuel injection system. They get fouled up, they don't work right, they take several hours, if everything does go right, to get the plant back up to the full capacity, so there's a whole host of questions.
I don't know if that question has ever been looked at, but clearly oil tanks aren't cheap. Alternative fuel systems --
PRESIDING MEMBER LAURIE: Well, the question comes to mind that certainly from a public policy perspective I would surmise that somebody is or should be thinking about our

situation that we'll find ourselves in ten or twenty years when the large majority of our electrical production comes from gas plants and that's the vulnerability of the system, should gas supply be threatened, which would equate to not only the gas supply being threatened but California's entire electrical supply being threatened.

That is not your responsibility, you know. Your responsibility is to your own areas of interest and I respect that. I would hope somewhere there is consideration being given about that potential vulnerability of electrical supply relying on a singular fuel.

MR. SEEDAL: Just a comment on that. I think that's a very good point and I do think that the state has the ability, if it plans today, to avoid that eventuality and I think it has that ability because the state is fortunate in having, at least one time, quite a large amount of natural gas in the state, which creates the potential for significant, in my view, natural gas storage in the state of California, which would then place under adverse conditions more reliability of gas service for all under high demand circumstances.

So perhaps if more thought is given to that alternative, which is clean of course when demands are high for keeping electric generation on anyway, it might meet both objectives, long term and short term.

PRESIDING MEMBER LAURIE: Thank you.

Mr. Wood, did you have a comment?

MR. WOOD: I was just thinking when you're talking about storage, who would be responsible for maintaining the inventory of gas in storage? Would Duke be responsible for that or would the utility or would the merchant storage operation be responsible? How do you see that, Mr. Seedal?

MR. SEEDAL: Well, I think it's going to depend on the market conditions and it will be a function of, you know, the amount of pipeline capacity that we would hold to get here vis-a-vis the amount of storage available, the cost of that storage, the incentives to hold the storage.

Clearly there is going to be a need, I think, to get a jump start on getting some more gas storage going, which mainly supports, you know, a core type load or a residential type load, at best, because it has such a peaked shape to it.

So there may be a need to have utilities, perhaps, invest further in getting the storage set up if we're really going to have a viable set of, you know, storage options for the state.

MR. WOOD: The only reason I asked the question is because there was an opportunity this last spring to put gas in the storage and the noncore customers did not make use of that and as a result noncore storage was not up to par where you would anticipate it should be for going into the winter, if you would. And I've seen that happen in the past in other periods of time when core -- there is storage allocated in the utility systems and then it hasn't been actually used, because of perceiving that there would be adequate supply and capacity to bring the gas into California during the winter months when sometimes that hasn't really been the case.

So I get into this, yeah, it's fine to have storage available, but somebody has to be responsible for putting that gas in the storage and then marketing it to whoever needs it. And whether it's in my mind, I could see this as being a merchant function for our gas storage operator, if need be, but if we just rely on our electric generators to put gas in storage I'm not so certain that we will really end up having that gas in storage when it's needed.

PRESIDING MEMBER LAURIE: I would assume that if the government determines that it's proper policy to provide such safeguards it is the governmental constituency that will end up being responsible to provide for it and it would not be the responsibility of individual merchant enterprises.

Mr. Tomashefsky, did you have a question?

MR. TOMASHEFSKY: The question, it seems that you can put as much storage as you want, but ultimately you're still subject to what capacity there is available to take the gas out of storage and deliver it.

For example, if you were to take the Wild Goose facility and double the size of it, it's not going to really do anything in terms of what you can provide in the San Diego region or something like that. So, you know, there are prospects for developing storage say in San Diego or some other parts of the SoCal Gas service territory that would be advantageous in terms of where you would choose to locate a powerplant as opposed to just generically saying we're going to go ahead and increase our storage capacity on the system and add the appropriate capacity to allow additional delivery capacity from various utility systems.

MR. SEEDAL: I'll just comment briefly. I mean clearly you need to add the appropriate distribution network to go with the gas storage system. Wild Goose is located particularly far north. There are a lot of other storage opportunities closer to the load center.

San Diego is a problem, because I don't know of any preexisting gas fuels in that area, so they have a little different circumstance, but clearly augmenting, you know, SoCal's territory and PG&E's territory with storage that's closer to the load center from gas fields, remember, that are closer to the load, which do exist, that haven't been exploited yet for gas storage, and then augmenting the distribution systems accordingly, you may be able to accomplish quite a bit of reliability rather than relying on, you know, distant interstate pipelines.

We haven't had the situation this year, for example, where we've had well freeze-offs and things like that that would disrupt supply from far away. So it kind of gets back to do you want to try to have more reliability, you know, for more of the people closer to the market center versus having that reliability further away, and who makes that decision.

I think clearly electric generators would say we have a pretty flat load often. We can manage with pipeline capacity pretty well. We might still pick up some storage, but a smaller customer who has a very great deal of seasonal load need, you know, who doesn't hold a lot of pipeline capacity may not make sense to you, because their loads vary from, you know, by a factor of four or five between summer and winter, may make a lot more sense to have storage on a system. And San Diego would have to be augmented differently because it doesn't have gas storage.

You may need LNG down there, I don't know, storage tanks to help that system.

MR. TOMASHEFSKY: I suppose ultimately you can get into a philosophical discussion about who should bear the costs of those particular expansions, because ultimately, at least in the current configuration, it's likely that the utility systems would have to be expanded in terms of capacity. But they may not necessarily be -- their customers may not be the beneficiaries of that expansion and so how do you deal with it.

I guess it's similar to the SMUD situation where there is an equity interest in the pipeline that SMUD owns so even though PG&E has Line 400, there's a portion of it that's actually owned by SMUD.

PRESIDING MEMBER LAURIE: Well, let me do this. I think it's appropriate to have those philosophical discussions and they will be initiated after five o'clock, sometime tonight, in order -- and it was my fault for taking us off track, I apologize.

Mark.

MR. SEEDAL: Let me just finish, I have one more point here.

On the curtailment rules themselves, we do think those curtailment rules need to be possibly redesigned, so that powerplants do receive sufficient gas supply to support an appropriate level of generation for the California electric market. And that in the design of those curtailment rules there needs to be some consideration of the reliability of the electric grid.

So right now I don't think the existing gas curtailment rules actually do that. So that's a consideration that we think should be maybe thought about.

And then in terms of, I think, an overarching principle for existing powerplants, in particular, that are hooked up to the grid, that are must-run, with existing gas distribution capacity, Brownfield type projects, that have already, again, paid for that existing capacity over a long period of time by their customers, especially if they are modernized, we think those plants should be given priority in terms of gas supply and gas distributions access for producing reliable electric generation.

Greenfield plants, for example, that are -- or plants that are located outside of an LDC service territory, for example, like in Mexico, that adversely affect the ability of the local distribution company to serve its core customers or its -- we think should be curtailed. And especially if they don't hold or bring on new transmission capacity or gas transportation capacity, we think those should be afforded the lowest priority in terms of curtailment of natural gas.

Thank you, very much.

PRESIDING MEMBER LAURIE: Thank you, sir.

Mr. Nazemi, good afternoon, sir.

MR. NAZEMI: Good afternoon. Thank you for allowing me to talk here. I want to give a very brief discussion on the air quality issues and to do that I just want to maybe paint a picture in terms of what's happening in South Coast with respect -- first I want to give you a quick overview of what has happened in the South Coast area.

The South Coast area that I am talking about first of all is Los Angeles, Orange and the western portions of San Bernardino and Riverside Counties. We have generation capacity about 10,700 megawatts that are all basically operating on natural gas. And although we have some 25 percent increase in capacity proposed to go through permitting and construction, as you very well know, not all of it is going to get built and then always there is an element of doubt if all proposed are ever going to get built.

So when we look at the historical situation in South Coast, the electric utility initially was under what we used to call a command and control program, where there were subject -- the utility boilers were subject to Rule 1135 and the gas turbine were subject to Rule 1134.

What basically the utility boiler rule did it created a systemwide bubble for various utilities that at the time were present in the South Coast. That meant Southern California Edison had its own bubble, the LADWP had its own and then the three cities, meaning Burbank, Glendale and Pasadena had their own bubbles.

And the concept was that systemwide they had to reduce their emissions over a time period to meet certain air quality objectives. As a result of a number of discussions in the early nineties with industry, South Coast moved forward to adopting a program which was an emission trading program. It was a program called reclaim and instituted a process where the industry would decide what's the best way to reduce their emissions and the most cost-effective way to reduce the emissions, and they would go ahead and do it without much of the agency involvement in terms of a command and control program.

This reclaim program was adopted in '93 and went into effect in January of '94. The program established facility emission caps for some 378 facilities in the programs and those caps would reduce annually through the year 2003 and it will stay flat from that point on. And that was consistent with the air quality management plan that was adopted at the time and submitted to the US EPA.

So what we saw historically was, as you heard earlier, through the eighties, the late eighties, a lot of the utilities were burning fuel oil for various reasons, one being economic. And, as a result of switching over to natural gas in the late eighties, they had some capabilities under Rule 1135, and that specifically dealt with gas curtailment concepts.

The reclaim program did not impose any specific requirement in terms of what kind of fuel you burned. It actually was silent to that effect. But as companies, utilities felt that it was cheaper to burn natural gas and it was a lower, cleaner fuel to be burned, they systematically switched over to natural gas.

And as of today one-third of the -- about one-third of the generation capacity that used to have capability to burn fuel oil has actually changed all their permits and they've removed that capability from their permits.

There's another third that still maintained that capability on the permits, but as you heard earlier the facilities were taken away. Southern California Edison, as you very well know, when they divested their facilities in the South Coast area, they maintained the fuel storage element of their facilities and converted them to storage for crude oil and they leased that to the oil companies through an extensive pipeline.

So that infrastructure has not been available to those that even maintained that on their permit.

There is still about a third of the generation capacity, that's mainly the municipalities that have that capability. However they have not exercised that since the late eighties, so nobody in practice is burning fuel oil in Southern California.

I think to give you an indication of the air quality aspects of it, if I could ask Rick to put on the first overhead.

When we looked through various regulatory programs at the existing utility system in Southern California, South Coast area, there's -- first of all the utility boilers, as you well know, are old units. They're over 30 years old, the majority of them, 60 percent of them.

As part of the reclaim program, what happened was because they had the ability to purchase credits instead of controlling the emissions, the utilities, in general, used that approach as it proved to be cost effective and delayed installation of controls.

So the picture that stands today is about a third of the generation capacity has controls installed. One may argue, well, that's not too bad. You know, a third of the generation capacity has controls so air quality should be relatively okay. But that's not the case, because once all the units fire up and if there is a need to run all the generation capacities, the emissions from the uncontrolled units would contribute to 95 percent of the total mass emissions that would be coming out of these units.

So it does raise a concern about relative emissions from utilities, even with natural gas.

Rick, if you could put on the second slide. Part of the reclaim program was intended to -- and I apologize, you may not be able to see that yellow line very well. But part of the reclaim program was intended to allow for the economic slump that we were in in the early nineties and not to restrict the facility emissions to a point where you cannot -- you start the program in a hole.

So the initial allocations for facilities in this program were above their 1991 and two activity level to allow for an economic slump at the time that we were in. And predictions and emissions had all come to a point where we had seen in the 1998-'99 timeframe the actual emissions would exceed the allocations unless people start to put on controls and reduce the emissions.

The picture for the overall program told us that in '99 we reached that point and there was no crossover but there was a certainty that there will be some if nothing happens.

The next slide will show you what happened with the utilities. The utilities were initially given an allocation that accounted for emissions reductions that would occur. However, because of delaying installation controls the utilities turned out to be the sole buyers of credit in the reclaim market. And, in fact, even though they kept their emissions below their overall allocation, but the yellow line was their allocation and the red line is what they actually purchased.

So it was clearly a market where utilities were buying credits rather than reducing their own emissions.

And the next slide, we'll take these two slides and combine them and give you a sense of what the impact of the utilities in terms of the overall reclaim -- in the reclaim program was. And that is, the tall bar is the total program emissions allocation. The red or orange is the utility allocation and the yellow is their actual emissions.

As you can see, come 1999 they began to actually emit more than their initial allocation or what was designed in the program for utility emissions. And certainly this year, although we haven't reached a reconciliation period, which is the end of February, we predict that that bar would be even bigger and greater than what you see there.

So, as a result of this, you have heard that the prices of credits in South Coast have become astronomical and they had -- as being one of the major buyers of the credits they were able to pay excessive amounts of money and still come out ahead because of the structure and the market price of the electricity and they raised the cost of credits to a point where the other participants in the reclaim program couldn't afford to purchase any more credits.

Now, having said that, last Friday our governing board did give the nod to staff to proceed with rule development which constituted pulling the utilities temporarily out of the reclaim market to the year 2003 and establish two elements.

One is to make sure that they're doing

the install controls and reducing the emissions. And secondly, to ask the utilities who exceed their emission levels to pay a nominal fee to a fund and have the district, in return, go out and purchase emission reduction credits or have projects come in and create emission reduction credits to compensate for these lost emissions. And those would be either in a stationary, mobile or area source type.

In addition, the board requested that an air quality improvement fund or investment program be also initiated for certain other companies in this program and they would also be able to take advantage of this and this would also be available to new powerplants who would come into the South Coast area, so that they are not starting in a hole again with the rest of the utilities.

As part of that I think we'll come to the next question and that is what are the alternative fuels available for utilities to burn? And we already talked about fuel oil, so when you look at the picture of emissions and allocations in this program, obviously once any one of the utilities wants to burn fuel oil, their NOX emissions are going to be anywhere from two to six times greater. And depending on what type of controls they've installed, they may or may not be actually able to run the fuel oil without poisoning the controls that have been installed to reduce emissions for natural gas.

So I would kind of agree with Mr. Seedal about not having too much reliance on the ability to burn fuel oil, not only because there is no infrastructure left to do that, but also because the air quality impacts would be significant if that was to happen.

Now, having said that, if one were to utilize fuel oil I think there is going to be an educated level of studies done on what availabilities there are. As you know, there are a number of low sulphur fuels being generated, produced by the refineries. There is also low nitrogen fuel oils, which would reduce nitrogen oxides emissions from burning that fuel, significantly.

So those are some of the alternatives, but I also want to talk about, quickly, what happens when the natural gas is curtailed and the electricity is curtailed, which we have seen in the last two or three weeks.

As a result of that, what we will end up with is the backup generators, which are all diesel fired, would come on line and those are real dirty units, because they basically have no controls. You have sometimes 300 times more NOX emissions compared to a brand new powerplant that would be going in, per megawatt of air or kilowatt of energy. And they also have a lot of toxics emissions associated with them, due to diesel particulate.

And finally, we've talked about the electric utility industry here, but gas curtailment has other effects on other industries. And that is in terms of industries that have options, they are looking at dirtier fuel and you might have heard that they are looking at yellow grease for certain industries. And there's also implications when their electricity or power is curtailed.

There are some industries, such as battery plants where they have lead emissions that would be initiated from those operations that immediately the air pollution control equipment that is operated with electric power is out of service. And they still have hot melting pots that's going to continue to emit lead into the atmosphere.

So it's not just the effect on standby generators. There are some types of industries that once their power is cut off, they're going to have significant amounts of emissions come out of their unit until they can bring the units down.

So, that's kind of like a quick overview of what the air quality implications are when we are looking at and talking about curtailment for natural gas.

I'd be happy to answer any questions.

PRESIDING MEMBER LAURIE: Thank you, sir, very much.

We'll have an opportunity to do so during the public comment period. Thank you.

Mr. Walters, good afternoon, sir.

MR. WALTERS: Yes, I'll address my comments specifically to stored fuels and specifically to gas turbines since those are the newer powerplants that are being built and I think the last speaker addressed a lot of the boiler alternate fuel issues.

You made, I think the first point I wanted to make, which was that the alternate fuels on site and near site are not only suitable for a design system where you might try and get through a cold weather period, but are also good for unplanned outages, pipeline accidents, and gives you that additional security, that designing the pipeline system really wouldn't compensate for.

The cost of stored fuel is going to greatly depend on what your design outage duration is going to be. If you're going to design it for one cold morning, it's going to be different than for a week period or for an extended pipeline interruption. So you can't really answer the cost question until you know what that duration will be.

The current experience with alternate fuels for gas turbines is pretty limited to peakers, because when gas turbine arrow or main frame peakers were used, the air emission issue was not as great and therefore it was typical to use the lowest cost option, which is to store number two distillates and have a dual fuel burning capability in the turbine.

Now, a number two distillate fell out of favor with some utilities because, if it's stored for a long period of time, typical of a backup fuel, it decomposes and then it becomes difficult when you really need it to use it. I think this issue was mentioned by Mark.

Some utilities, therefore specify that they only will use jet fuel as backup and that somewhat gets around some of the problems that people have experienced with number two distillate.

The pre-investment, however, I think is going to be somewhat expensive, because if you're going to try and meet the same air emission requirements, for a distillate fuel, while it's possible to use a dry load ox burner, generally the arrow derivative turbines are not going to be able to have enough space for that type where you vaporize the fuel, then mix it and then try and do dry well NOX. Which means you might have to significantly overinvest in an SRC system in order to be able to meet NOX when burning a dirtier fuel as well as when burning natural gas.

Another issue affecting air emissions is that if you're going to have a reliable backup system, you must use it periodically. This may mean something like running it monthly, as a typical diesel backup for electric power.

So the air emission would not only occur during your emergency condition, but would occur periodically and would have to be accounted for offsets or whatever would be required for it to be used.

There are other options which may be more expensive which could use cleaner fuels. LNG storage is a technology which would be an option, in which you would have natural gas as your stored backup fuel and your generation system, therefore, would be unaffected. This is expensive and, of course, energy intensive. It takes a lot of energy to convert natural gas to LNG and a lot of energy to revaporize it.

Another option that has been used by gas utilities for many years for making up for winter shortages of natural gas is to use propane air mixtures and then blend that in with natural gas or it could be used purer. The reason for using propane air is that it has the same volumetric Btu content as natural gas.

I don't know of anyone who's ever tried to use this fairly low-cost storage system in a gas turbine. It would probably burn in the burner, but the dry loan ox burner probably would not work as well because the flame speed of the propane is considerably higher than the natural gas, so this would involve some design work on the part of turbine manufacturers.

But I think, cutting it short, the bottom line on stored fuels is going to be, you have to determine what interruption you're designing it for, what are your air emission constraints that you're going to place on it and then you're going to be, as other speakers have indicated, you're going to have to do a cost benefit analysis on what you have left.

PRESIDING MEMBER LAURIE: Thank you, sir, very much.

Any comments by the panel before we ask the public for their questions?

None.

Gentlemen, thank you. If you can hold on and we'll see if the members of the public have any questions for us.

At this time I would welcome questions or comments.

Mr. Williams.

If you can state your name for the record, sir.

MR. WILLIAMS: Yes, sir. Thank you, Commissioner Laurie. I'm Robert Williams, retired expert in electrical energy but new to this siting business.

I have four brief questions that I think will illuminate some pretty crucial issues. The first is, I would like to ask the panel do they agree or disagree that it would be reasonable to ask each powerplant, each gas-fired powerplant as part of a policy bargain in return for being included in the uninterruptable supply to supply a five or ten-day natural gas reserve. Does that appear to you to be reasonable?

It would seem to me it would be in two components, a storage component and a margin and compressor capacity. It strikes me that that would be only a $10 or $20 million investment.

PRESIDING MEMBER LAURIE: Well, let's ask the question, Mr. Williams. Any panel member have any thoughts about that question?

MR. THOMAS: Well, from, I guess, a utility standpoint as a provider of storage services, I continue to believe that, in fact, if you want to ensure generation year round, the generators have to have some type of capability.

And I don't think Northern California really is the place to have alternative fuels and so I do turn to basically storage requirements, that somebody needs to hold it and pay for it. And if it's the generators that need that reliability, then that should be built into the price of their contracts that they have to provide power.

PRESIDING MEMBER LAURIE: Anybody else, any comment?

Thank you.

MR. WILLIAMS: Do you have an opinion about the approximate cost?

MR. THOMAS: No, I don't, I haven't looked at that.

PRESIDING MEMBER LAURIE: Commissioner Pernell.

COMMITTEE MEMBER PERNELL: What size of -- I'm assuming that this would be in a tank or underground. What size of tank would it take to store that type of natural gas for a -- I don't know, even a 24-hour period?

MR. THOMAS: Well, we at PG&E would just essentially expand our existing storage facilities. I think I pointed out this morning that you could expand one of our fields for around

$75 million, I believe was the figure that I referenced.

COMMITTEE MEMBER PERNELL: Expand your natural gas field.

MR. THOMAS: We already own several natural gas fields. It's just a matter of putting more equipment in place to allow you to cycle the gas more, to put more gas in storage.

MR. SEEDAL: I might just comment. A 500-megawatt, one of these new 500-megawatt combined cycle plants, just to give you an idea of how much storage a week, would use about 80 million cubic feet a day. And so if you had seven days, full out, full load, seven days, that would be about half a Bcf of gas supply somewhere, if you couldn't get gas to the plant for seven days, just as an idea of how much gas we're talking about for each plant.

MR. WILLIAMS: Thank you.

Second question relates to the policy implications of diversity of energy supply. From my experience in the business, at least under regulation, there was a policy of diversity between hydro power and nuclear power, natural gas. And it strikes me that it might still be good policy to cap the natural component of generation at between 40 and 50 percent of the total. Does anyone want to comment on that?

MR. SEEDAL: I can comment. We cannot imagine, at Duke, permitting anything other than a natural gas facility in California. I can't imagine --

PRESIDING MEMBER LAURIE: Given what current environmental --

MR. SEEDAL: Given current environmental rules, a coal plant, I would find that very difficult. Maybe there's a hydro plant somewhere that may be still left undone, I don't know. Nuclear plant, I can't imagine it in terms of the siting difficulties of those other options other than gas fired.

MR. WILLIAMS: Well, I do appreciate those other options. That brings me to my fourth question. I believe there's a potential interaction between the water supply of the state and the power supply. It would manifest itself first as something arguably like a nuclear plant being used to manage the operation of the hydro plant so that water were not discharged willy-nilly.

Secondly, I spent the early part of my career in nuclear. And nuclear is competitive between three and four dollars for MBtu on natural gas or in the Governor's pricing scheme, new nuclear units are competitive if they are between five and five and a half cents per kilowatt hour.

So I think between -- I wonder if anyone would comment on the potential benefit 20 and 30 years down the road of using nuclear to manage the discharge from the hydro powerplants?

PRESIDING MEMBER LAURIE: Don't hear any comments from this particular panel, sir.

MR. WILLIAMS: Okay, fine.

My last question, don't you think at some point it would be appropriate to consider the exhaustion of these energy ERCs, these pollution credits and just require full litigation of the discharge? It seems to me that's been a transition major that should expire eventually.

MR. NAZEMI: In a way that's what we are planning to do as part of the bifurcation. Not exactly what you said, but it's a step in that direction. But there would be both an element of control and some mitigation in terms of looking for reduction somewhere else if they can begin from the utilities.

MR. WILLIAMS: It was your thought that provoked the question -- I missed your organization, sir.

MR. NAZEMI: I'm with South Coast Air Quality Management District.

MR. WILLIAMS: South Coast Air --

MR. NAZEMI: It's a local air quality district.

MR. WILLIAMS: Thank you very much, sir.

PRESIDING MEMBER LAURIE: Yes, sir.

Any other comments or questions?

Yes, sir.

MR. MOORE: Steven Moore, San Diego Air Pollution Control District.

I just have a quick question for Mr. Nazemi. Have you looked at the local impacts of burning alternative fuels? I know in San Diego there's probably going to be considerable local impact from like sulphur dioxide and PM10, from burning residual fuel oil in the local powerplants.

MR. NAZEMI: The answer is we have not seriously looked at it, because that has not been a serious option. But, as you all know, the South

Coast is in containment status with sulphur dioxide standards and we have not seen any exceedances for a long period of time, but there are other emissions, such as toxics and other things associated with fuel oil and those certainly need to be reevaluated.

PRESIDING MEMBER LAURIE: Anybody else? Yes, sir.

MR. AKABA: My name is Azibuike Akaba with Communities for a Better Environment.

The question I asked earlier is are there any existing regulatory priorities for when the gas shortage happens, in terms of like homes or residential being supplied gas as opposed to like industry uses in terms of curtailment.

PRESIDING MEMBER LAURIE: Well, let me turn to Mr. Thomas whose presentation did talk about the regulatory rules. Thank you, sir, and perhaps you can just again summarize for purposes of background.

MR. THOMAS: Yeah, the rules are in any crisis, the residential and small commercial customers get served first. And so you would turn off, in the case of generation, you'd turn off generation, you'd turn off industrial customers, so to ensure that the residential consumer would still get their natural gas.

MR. AKABA: Thank you.

Okay. The next question is directed towards Mr. Nazemi about the reclaim program. So is there a cap on how much credits the electricity generating industry can purchase and when will it be mandatory that they have to purchase pollution control equipment?

MR. NAZEMI: Okay, what I said was that at last Friday's board meeting, our board directed us to begin rule development and in the next -- on a fast track basis, in the next two to three months we will be bringing back rules that would explain all the details in your question.

But in general what we are looking at that there would be some minimum requirements in terms of air pollution control that have to be installed. And the details of how much credits can or should be available is all going to be worked out in the next few months.

MR. AKABA: Okay, because we had experienced a challenge in the reclaim and to date from the inception of the program it hasn't worked in terms of reducing the pollution being generated. Just the companies have been purchasing more and more credits but they actually have not been able to reduce the generational pollution.

PRESIDING MEMBER LAURIE: Thank you, sir very much.

Good afternoon.

MS. RYAN: Nancy Ryan, Environmental Defense. I have a question for Mr. Nazemi. You mentioned that, I think, as a result of electricity curtailments, it was battery plants will actually increase their -- their lead emissions may increase. Can you think of other examples or has that kind of phenomenon been examined comprehensively?

MR. NAZEMI: I can't think of any other ones right offhand, but as you well may know there are a number of, for example, refineries and other large industrial operations that you can't just turn off the FCC unit on a snap when the power goes out. And although many of them have in place an emergency plan on how they would deal with issues such as power outages and curtailments and other disasters, there are still potentials for air emissions to occur.

And if they don't have enough, for example, flaring capacity to burn off all the waste gas within the system, that could cause some additional increase in emissions.

MS. RYAN: And are there similar problems in the face of a gas curtailment, gas-fired powerplants coming on and off line, does that affect their emissions?

MR. NAZEMI: I don't believe that that would be the issue with gas-fired plants. However, I would also seek the experts here if they know of any potential impacts.

MR. SEEDAL: It's clear there's different -- I'm not an air expert per se, but there certainly are different increased impacts of starting up a powerplant versus having it running, you know. And so every time you ramp it off and have to turn it back on, there's a little higher emissions. It's not -- I wouldn't consider it hugely adverse.

MS. RYAN: Thank you.

PRESIDING MEMBER LAURIE: Anybody else?

Well, let me offer our appreciation to the panel. It is the Committee's intent to sometime around April publish a report, entitled something like "Commissioner Pernell's Ponderings About Potential Barriers to Licensing of Powerplants in California".

(Laughter.)

PRESIDING MEMBER LAURIE: And your comments today will show up in chapter one.

Deeply appreciated, very helpful. We appreciate your sacrifices in being here today and we thank you very much.

COMMITTEE MEMBER PERNELL: Thank you.

PRESIDING MEMBER LAURIE: And I'm sorry, Commissioner Pernell, did you have any comments?

COMMITTEE MEMBER PERNELL: No, I didn't.

PRESIDING MEMBER LAURIE: I'm sorry, Robert.

COMMITTEE MEMBER PERNELL: Other than, we'll have more than one chapter.

(Laughter.)

PRESIDING MEMBER LAURIE: I think we're talking about water in about two weeks.

Thank you.

(Thereupon the Energy Commission Siting Committee Workshop was concluded at 2:37 P. M.)

CERTIFICATE OF REPORTER

I, VALORIE PHILLIPS, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Siting Committee Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said Workshop, nor in any way interested in the outcome of said Workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 5th day of February, 2001.

VALORIE PHILLIPS